

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

(X) QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended **June 30, 2000**

-- OR --

() TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____

Commission file number **1-4566**

THE MONTANA POWER COMPANY

(Exact name of registrant as specified in its charter)

Montana
(State or other jurisdiction
of incorporation)
40 East Broadway, Butte, Montana
(Address of principal executive offices)

81-0170530
(IRS Employer
Identification No.)
59701-9394
(Zip Code)

Registrant's telephone number, including area code **(406) 497-3000**

(Former name, former address and former fiscal year,
if changed since last report.)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes X No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date.

On August 7, 2000, the Company had 105,630,296 shares of common stock outstanding.

PART I
ITEM 1 - FINANCIAL STATEMENTS
THE MONTANA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF INCOME
(Unaudited)

	Six Months Ended	
	June 30, 2000	June 30, 1999
	(Thousands of Dollars) (except per-share amounts)	
REVENUES.....	\$ 698,931	\$ 631,268
EXPENSES:		
Operations.....	382,439	308,409
Maintenance.....	37,111	39,947
Selling, general, and administrative.....	70,657	64,173
Taxes other than income taxes.....	46,576	51,106
Depreciation, depletion, and amortization.....	50,313	55,355
	<u>587,096</u>	<u>518,990</u>
INCOME FROM OPERATIONS.....	111,835	112,278
INTEREST EXPENSE AND OTHER INCOME:		
Interest.....	20,358	26,500
Distributions on mandatorily redeemable preferred securities of subsidiary trusts.....	2,746	2,746
Other income - net.....	<u>(14,496)</u>	<u>(6,495)</u>
	<u>8,608</u>	<u>22,751</u>
INCOME TAXES.....	<u>35,531</u>	<u>30,454</u>
NET INCOME.....	67,696	59,073
DIVIDENDS ON PREFERRED STOCK.....	<u>1,845</u>	<u>1,845</u>
NET INCOME AVAILABLE FOR COMMON STOCK.....	<u>\$ 65,851</u>	<u>\$ 57,228</u>
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING - BASIC (000).....	105,575	110,165
BASIC EARNINGS PER SHARE OF COMMON STOCK.....	<u>\$ 0.62</u>	<u>\$ 0.52</u>
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING - DILUTED (000).....	106,899	110,940
DILUTED EARNINGS PER SHARE OF COMMON STOCK.....	<u>\$ 0.62</u>	<u>\$ 0.52</u>

The accompanying notes are an integral part of these financial statements.

THE MONTANA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF INCOME
(Unaudited)

	Quarter Ended	
	June 30, 2000	June 30, 1999
	(Thousands of Dollars) (except per-share amounts)	
REVENUES.....	\$ 334,067	\$ 309,500
EXPENSES:		
Operations.....	175,746	154,849
Maintenance.....	19,835	20,317
Selling, general, and administrative.....	33,729	31,030
Taxes other than income taxes.....	20,245	25,338
Depreciation, depletion, and amortization.....	25,208	27,601
	<u>274,763</u>	<u>259,135</u>
INCOME FROM OPERATIONS.....	59,304	50,365
INTEREST EXPENSE AND OTHER INCOME:		
Interest.....	8,968	12,871
Distributions on mandatorily redeemable preferred securities of subsidiary trusts.....	1,373	1,373
Other income - net.....	(6,153)	(2,626)
	<u>4,188</u>	<u>11,618</u>
INCOME TAXES.....	18,699	13,498
NET INCOME.....	36,417	25,249
DIVIDENDS ON PREFERRED STOCK.....	922	922
NET INCOME AVAILABLE FOR COMMON STOCK.....	<u>\$ 35,495</u>	<u>\$ 24,327</u>
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING - BASIC (000).....	105,598	110,184
BASIC EARNINGS PER SHARE OF COMMON STOCK.....	<u>\$ 0.34</u>	<u>\$ 0.22</u>
AVERAGE NUMBER OF COMMON SHARES OUTSTANDING - DILUTED (000).....	106,664	111,098
DILUTED EARNINGS PER SHARE OF COMMON STOCK.....	<u>\$ 0.33</u>	<u>\$ 0.22</u>

The accompanying notes are an integral part of these financial statements.

THE MONTANA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET
(Unaudited)

ASSETS

	June 30, 2000	December 31, 1999
	(Thousands of Dollars)	
PLANT AND PROPERTY IN SERVICE:		
UTILITY PLANT (includes \$21,863 and \$3,782 plant under construction)		
Electric.....	\$ 1,062,453	\$ 1,050,344
Natural Gas.....	419,069	416,383
	1,481,522	1,466,727
Less - accumulated depreciation, depletion, and amortization.....	487,497	464,653
	994,025	1,002,074
NONUTILITY PROPERTY (includes \$139,406 and \$134,817 property under construction).....	1,205,187	1,051,750
Less - accumulated depreciation, depletion, and amortization.....	399,069	349,088
	806,118	702,662
	1,800,143	1,704,736
INTANGIBLES (net of accumulated amortization of \$926 and \$317).....	154,506	922
MISCELLANEOUS INVESTMENTS:		
Telecommunications investments.....	42,720	39,678
Reclamation fund.....	44,636	43,459
Other.....	56,513	76,382
	143,869	159,519
CURRENT ASSETS:		
Cash and cash equivalents.....	13,276	554,407
Temporary investments.....	-	40,417
Accounts receivable, net of allowance for doubtful accounts.....	153,621	182,248
Notes receivable.....	22,114	-
Materials and supplies (principally at average cost)..<	36,448	37,928
Prepayments and other assets.....	80,186	53,733
Deferred income taxes.....	20,688	18,303
	326,333	887,036
DEFERRED CHARGES:		
Advanced coal royalties.....	12,526	12,506
Regulatory assets related to income taxes.....	60,539	60,538
Regulatory assets - other.....	149,961	150,486
Other deferred charges.....	36,879	73,000
	259,905	296,530
	\$ 2,684,756	\$ 3,048,743

The accompanying notes are an integral part of these financial statements.

THE MONTANA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEET
(Unaudited)

LIABILITIES AND SHAREHOLDERS' EQUITY

	June 30, 2000	December 31, 1999
	(Thousands of Dollars)	
CAPITALIZATION:		
Common shareholders' equity:		
Common stock (240,000,000 shares without par par value authorized; 110,297,787 and 110,218,973 shares issued).....	\$ 703,915	\$ 702,773
Treasury stock (4,682,100 shares authorized, issued, and repurchased by the Company).....	(144,872)	(144,872)
Unallocated stock held by trustee for Retirement Savings Plan.....	(18,850)	(20,401)
Retained earnings and other shareholders' equity....	520,386	488,975
Accumulated other comprehensive loss.....	(19,448)	(17,659)
	1,041,131	1,008,816
Preferred stock.....	57,654	57,654
Company obligated mandatorily redeemable preferred securities of subsidiary trust, which holds solely Company junior subordinated debentures.....	65,000	65,000
Long-term debt.....	366,294	618,512
	1,530,079	1,749,982
CURRENT LIABILITIES		
Long-term debt - portion due within one year.....	39,429	58,955
Short-term borrowing.....	65,000	-
Dividends payable.....	23,203	22,746
Income taxes.....	32,718	152,739
Other taxes.....	44,936	54,630
Accounts payable.....	91,251	115,654
Interest accrued.....	10,476	11,597
Other current liabilities.....	103,845	92,277
	410,858	508,598
DEFERRED CREDITS:		
Deferred income taxes.....	14,743	8,847
Investment tax credits.....	13,171	13,330
Accrued mining reclamation costs.....	136,901	135,075
Deferred revenue.....	256,718	311,751
Net proceeds from the generation sale.....	215,503	219,726
Other deferred credits.....	106,783	101,434
	743,819	790,163
CONTINGENCIES AND COMMITMENTS (Notes 2 and 5)		
	\$ 2,684,756	\$ 3,048,743

The accompanying notes are an integral part of these financial statements.

THE MONTANA POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENT OF CASH FLOWS
(Unaudited)

	For Six Months Ended	
	June 30, 2000	June 30, 1999
	(Thousands of Dollars)	
NET CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Income.....	\$ 67,696	\$ 59,073
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, and amortization.....	50,313	55,355
Deferred income taxes.....	3,352	(28,816)
Noncash earnings from unconsolidated investments...	(7,308)	(7,704)
Gains on sales of property and investments.....	(33,226)	(2,408)
Other noncash charges to net income - net.....	7,727	3,765
Changes in assets and liabilities:		
Accounts and notes receivable.....	6,513	51,949
Income taxes.....	(120,021)	(140,636)
Accounts payable.....	(24,403)	(12,493)
Generation asset sale - net proceeds.....	(4,223)	-
Deferred revenue and other.....	(55,033)	243,589
Temporary investments.....	40,417	-
Other assets and liabilities - net.....	26,065	(12,038)
Net cash provided by (used for) operating activities.	(42,131)	209,636
NET CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures - other.....	(108,012)	(76,141)
Qwest acquisition.....	(205,883)	-
Proceeds from sales of property and investments.....	66,769	10,238
Additional investments.....	(1,207)	(3,310)
Net cash used for investing activities.....	(248,333)	(69,213)
NET CASH FLOWS FROM FINANCING ACTIVITIES:		
Dividends paid.....	(44,082)	(45,909)
Sales of common stock.....	1,021	590
Issuance of long-term debt.....	17,435	24,902
Retirement of long-term debt.....	(290,041)	(76,402)
Net change in short-term borrowing.....	65,000	(53,720)
Net cash used for financing activities.....	(250,667)	(150,539)
CHANGE IN CASH FLOWS.....	(541,131)	(10,116)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD.....	554,407	10,116
CASH AND CASH EQUIVALENTS, END OF PERIOD.....	\$ 13,276	\$ -
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:		
Cash Paid During Six Months For:		
Income taxes, net refunds.....	\$ 154,004	\$ 196,068
Interest.....	23,998	30,835

The accompanying notes are an integral part of these financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying consolidated financial statements of The Montana Power Company for the interim periods ended June 30, 2000 and 1999 are unaudited. In the opinion of management, the accompanying consolidated financial statements reflect all normally recurring accruals necessary for a fair statement of the results of operations for those interim periods. Results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year, and these financial statements do not contain the detail or footnote disclosure concerning accounting policies and other matters that would be included in full fiscal year financial statements. Therefore, these statements should be read in conjunction with our audited financial statements included in our Annual Report on Form 10-K for the year ended December 31, 1999.

We have made reclassifications to certain prior-year amounts to make them comparable to the 2000 presentation. These changes had no significant effect on previously reported results of operations or shareholders' equity.

NOTE 1 - DEREGULATION, REGULATORY MATTERS, SALE OF ELECTRIC GENERATING ASSETS, AND PROPOSED DIVESTITURE OF ENERGY BUSINESSES

Deregulation

The electric and natural gas utility businesses are in transition to a competitive market in which commodity energy products and related services are sold directly to wholesale and retail customers. Montana's 1997 Electric Utility Industry Restructuring and Customer Choice Act (Electric Act) provides that all customers will be able to choose their electric supplier by July 1, 2002. Montana's 1997 Natural Gas Utility Restructuring and Customer Choice Act (Natural Gas Act) provides that a utility may voluntarily offer its customers choice of natural gas suppliers and provide open access. Since natural gas restructuring is voluntary, no deadline for choice exists.

Electric

Through June 30, 2000, approximately 1,200 electric customers representing more than 1,750 accounts crossing all customer classifications - or approximately 27 percent of our pre-choice electric load - have moved to competitive supply since the inception of customer choice on July 1, 1998. Residential customers were eligible to move to choice during the fourth quarter of 1998. However, the majority of the load associated with our pre-choice electric customers that moved to other suppliers was industrial and large commercial customers, and most of the activity in the second quarter 2000 was from residential and small commercial customers.

As required by the Electric Act, we filed a comprehensive transition plan with the Montana Public Service Commission (PSC) in July 1997. On July 1, 1999, we filed a case with the PSC to resolve the remaining Tier II issues under the filing. Tier II issues address the recovery and treatment of the Qualifying Facility (QF) power-purchase contract costs, which are above-market costs; regulatory assets associated with the electric generating business; and a review of our electric generating assets sale, including the treatment of sales proceeds above the book value of the assets.

In implementing our comprehensive transition plan, we initiated litigation in Montana District Court in Butte to address our ability to use tracking mechanisms to ensure fair and accurate recovery of above-market QF costs and certain other transition costs. We also sought court clarification on whether the Electric Act authorized a rate moratorium or a rate cap during

the transition period that ends July 1, 2002.

The district court issued an order in May 2000. The court ruled that the PSC must allow us to incorporate tracking mechanisms in our transition plan proposal. The court also ruled that the Electric Act authorized a rate cap. The PSC appealed the court's decision regarding tracking mechanisms, and we declined to appeal its decision regarding the rate moratorium.

After the district court case, we updated our Tier II filing to reflect the closing of the sale of our electric generating assets. The PSC has suspended the procedural schedule and, therefore, we do not expect an order from the PSC until 2001.

Natural Gas

Through June 30, 2000, approximately 240 natural gas customers with annual consumption of 5,000 dekatherms or more - 52 percent of our pre-choice natural gas supply load - have chosen alternate suppliers since the transition to a competitive natural gas environment began in 1991.

Regulatory Matters

Electric/Federal Energy Regulatory Commission (FERC)

On March 30, 1998, we submitted a cost-of-service filing with the FERC to increase our open access transmission rates and the rates for bundled wholesale electric service to two rural electric cooperatives. FERC approved an interim increase in rates charged for transmission service, pending final approval in 2000.

In January 1999, we reached a rate settlement with one of the cooperatives that moved to another supplier in December 1999. In March 1999, we reached a separate settlement with the other cooperative, agreeing to assist the cooperative's move to choice when its full-service wholesale contract expired in exchange for its agreement to withdraw its rate-reduction complaint. This cooperative moved to another supplier in June 2000.

Through a stranded-costs filing with FERC in April 2000, we are seeking recovery of approximately \$23,800,000 in transition costs associated with serving both of the wholesale electric cooperatives. We do not expect a FERC decision on this filing, which corresponds with our transition-costs recovery proceedings with the PSC in Montana, until 2001.

Electric/PSC

In January 2000, as a result of the sale of our electric generating assets and sales proceeds exceeding the book value of the assets sold, we filed a voluntary rate reduction with the PSC for approximately \$16,700,000 annually. This reduction became effective February 2, 2000.

On August 11, 2000, we filed a combined rate case with the PSC, seeking increased electric and natural gas rates. We requested increased annual electric transmission and distribution revenues of approximately \$38,500,000, with a proposed interim annual increase of approximately \$24,900,000. We expect a decision from the PSC regarding our interim request during the fourth quarter of 2000 and a final order in April 2001.

Natural Gas/PSC

On August 12, 1999, we filed a natural gas rate case with the PSC requesting increased annual revenues of \$15,400,000, with a proposed interim increase of \$11,500,000. An interim increase of \$7,600,000 became effective on December 10, 1999, and a final PSC order that became effective on April 1, 2000 approved an additional increase of \$2,800,000.

As discussed above, we submitted a combined filing with the PSC on August 11, 2000, seeking increased natural gas and electric rates. We requested increased annual natural gas revenues of approximately \$12,000,000, with a proposed interim annual increase of approximately \$6,000,000. We expect a decision from the PSC regarding our interim request during the fourth quarter of 2000 and a final order in April 2001.

Sale of Electric Generating Assets

As expected, the sale of our electric generating assets in December 1999 reduced the utility's net income for second quarter 2000. Utility revenues decreased because of discontinued off-system revenues related to the electric generating assets sold. Before the sale, revenues covered the costs of operating the generating plants, taxes and interest, and earned a return on our shareholders' investment. Since the sale, we continue to bill for energy supply, but now these revenues cover the costs of purchased power to serve our core customers. While revenues from our core customers were not affected by the sale, we now pay the profit component of revenues to the purchaser of the assets as part of purchased power expenses. Prior to the sale, this component represented the return on our shareholders' investment. As we now purchase most of the power to serve our core customers pursuant to buyback contracts, we reflect these costs in operating expenses as power supply expenses. The maximum price that we pay for power in the buyback contracts, \$22.25/MWh, represents our net fully allocated costs of service in current rates, replacing operations and maintenance expense, property tax expense, depreciation expense, and return on investment.

In the sale of these assets, we generally retained all pre-closing obligations, and the purchaser generally assumed all post-closing obligations. However, with respect to environmental liabilities, the purchaser assumed all pre-closing (with three limited exceptions) and post-closing environmental liabilities associated with the purchased assets.

While the purchaser assumed pre-closing environmental liabilities, we agreed to indemnify the purchaser, on a limited basis, from losses arising from required remediation of pre-closing environmental conditions, whether known or unknown at the closing. During the second quarter 2000, we received no claim notices related to this indemnity obligation. We do not expect this indemnity obligation to have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

Proposed Divestiture of Energy Businesses

On March 28, 2000, we announced our decision to separate our telecommunications business from our energy businesses through stock sales of our energy businesses. When we complete the sales, expected to take six to twelve months from the end of the first quarter 2000, Touch America, Inc. will remain as the entity through which we will continue to conduct our telecommunications business. We intend to invest the net proceeds received from the sale of our energy businesses into Touch America.

NOTE 2 - CONTINGENCIES

Kerr Project

A FERC order that preceded our sale of the Kerr Project required us to implement a plan to mitigate the effect of the Kerr Project operations on fish, wildlife, and habitat. To implement this plan, we were required to make payments of approximately \$135,000,000 between 1985 and 2020, the term during which we would have been the licensee. The net present value of the total payments, assuming a 9.5 percent annual discount rate, was approximately \$57,000,000, an amount we recognized as license costs in plant and long-term debt on the Consolidated Balance Sheet in 1997. In the sale of the Kerr Project, the purchaser of our electric generating assets assumed the obligation to make post-closing license compliance payments.

In December 1998 and January 1999, we asked the United States Court of Appeals for the District of Columbia Circuit to review FERC's orders and the United States Department of Interior's conditions contained in them. On September 17, 1999, the court granted the motion of the parties and intervenors to hold up the appeal pending settlement efforts. In December 1999, we, along with the purchaser of our generating assets, the United States Department of the Interior, the Confederated Salish and Kootenai Tribes (the Tribes), and Trout Unlimited, in a court-ordered mediation, agreed in principle to settle this litigation.

A Statement of Agreement containing the principles for settlement of the disputes underlying the appeals was developed in December 1999. It provides that its terms are binding against all parties, with the understanding that the signatory parties would jointly draft additional documents as necessary to establish the terms of the settlement in detail. The parties have submitted these documents to FERC, and we have paid our settlement payment of approximately \$24,000,000 under the Statement of Agreement into an escrow account. If FERC approves, in a final non-appealable order, the settlement terms as reflected in proposed license amendments discussed below, we will dismiss the petitions in the court of appeals, and the escrow agent will release the payments to the Tribes. In addition, we will transfer to the Tribes 669 acres of land we own on the Flathead Indian Reservation. If FERC does not approve the proposed license amendments in the form agreed to by the parties, or if, as a result of the appeal of a FERC order, that order is not final after a specified period, the money will be returned to us, and the litigation will resume. The settlement, subject to the conditions described above, substantially reduces our obligation to pay for fish, wildlife, and habitat mitigation assigned to the pre-closing period in the sale of the Kerr Project.

In April 2000, the purchaser of our generating assets and the Tribes, as co-licensees, filed proposed license amendments with FERC to effect the settlement described above. We supported these proposed license amendments. FERC is reviewing the filing, but we do not expect a decision until late 2000 or early 2001.

Miscellaneous

We and our subsidiaries are parties to various other legal claims, actions and complaints arising in the ordinary course of business. We do not expect the conclusion of any of these matters to have a material adverse effect on our consolidated financial position, results of operations, or cash flows.

NOTE 3 - DERIVATIVE FINANCIAL INSTRUMENTS

Derivative Financial Instruments Used

We use derivative financial instruments to reduce earnings volatility and stabilize cash flows by hedging some of the price risk associated with our nonutility energy commodity-producing assets, contractual commitments for firm supply, and natural gas transportation agreements. We also use derivative financial instruments in speculative transactions to seek enhanced profitability based on expected market movements, as discussed below in "Speculative Transactions." In all cases, financial swap and option agreements constitute the principal kinds of derivative financial instruments used for these purposes.

Swap Agreements

Under a typical swap agreement, we make or receive payments based on the difference between a specified fixed price and a variable price of crude oil or natural gas at the time of settlement. The variable price is either a crude oil or natural gas price quoted on the New York Mercantile Exchange or a natural gas price quoted in Inside FERC's Gas Market Report or other recognized industry index.

Option Agreements

Under a typical option agreement, we make or receive monthly payments based on the difference between the actual price of crude oil or natural gas at settlement and the price established in a private agreement at the time of execution. Making or receiving payments is dependent on whether we buy (own or hold) or sell (write or issue) the option. Buying options involves paying a premium - the price of the option - and selling options involves receiving a premium. When we use options, we defer all premiums paid or received and recognize the applicable expenses or revenues monthly throughout the option term. As of June 30, 2000, we paid more in option premiums than we received, resulting in deferred expenses of approximately \$800,000.

Hedged Transactions

Hedged transactions are those in which we have a position (either current or anticipated) in an underlying commodity or derivative of that commodity that exposes us to risk if the price of the underlying item adversely changes. We enter into these transactions primarily to reduce earnings volatility and stabilize cash flows. We recognize gains or losses from these derivative financial instruments in the Consolidated Statement of Income at the same time that we recognize the revenues or expenses associated with the underlying hedged item; until then, we do not reflect these gains or losses in our financial statements. In April and May 2000, we terminated hedging instruments associated with ongoing natural gas sales and transportation contracts and are recognizing total gains of approximately \$15,000,000 over the original periods covered by the hedging instruments (May 2000 through December 2000 for a portion of the gain and July 2000 through December 2000 for a portion of the gain). During the second quarter 2000, we recognized as income approximately \$1,400,000 of the total gain.

At June 30, 2000, we had swap and option agreements on approximately:

- 1,278,000 barrels, or 42 percent, of our estimated nonutility crude oil and natural gas liquids production through March 2002;
- 21 Bcf, or 66 percent, of our expected delivery obligations under long-term natural gas sales contracts through October 2001; and
- 0.12 Bcf, or 4 percent, of our natural gas production through December 2000.

In addition, at June 30, 2000, we had sold swap and option agreements to hedge approximately 27 Bcf of our nonutility natural gas pipeline transportation obligations under contracts through December 2001, and we had purchased swap and option agreements to hedge approximately 33 Bcf of these obligations.

Speculative Transactions

We also enter into derivative financial transactions in which we have no underlying price risk exposure nor any interest in making or taking delivery of crude oil or natural gas commodities. We seek, by these speculative transactions, to profit from the market movements of the prices of these commodities. In accordance with Emerging Issues Task Force Issue No. 98-10, we mark to market all of our speculative transactions and recognize any corresponding gain or loss in the Consolidated Statement of Income. As of June 30, 2000, we had unrealized mark-to-market losses of approximately \$2,200,000 related to these speculative transactions.

NOTE 4 - COMPANY OBLIGATED MANDATORILY REDEEMABLE PREFERRED SECURITIES OF SUBSIDIARY TRUST

We established Montana Power Capital I (Trust) as a wholly owned business trust to issue common and preferred securities and hold Junior Subordinated Deferrable Interest Debentures (Subordinated Debentures) that we issue. The Trust has issued 2,600,000 units of 8.45 percent Cumulative Quarterly Income Preferred Securities, Series A (QUIPS). Holders of the QUIPS are entitled to receive quarterly distributions at an annual rate of 8.45 percent of the liquidation preference value of \$25 per security. The sole asset of the Trust is \$67,000,000 of our Subordinated Debentures, 8.45 percent Series due 2036. The Trust will use interest payments received on the Subordinated Debentures that it holds to make the quarterly cash distributions on the QUIPS.

NOTE 5 - COMMITMENTS

Touch America's Commitments

Construction Projects

Touch America has contracted with Northern Telecom, Inc. (Nortel) to furnish and install optical electronic equipment on certain fiber-optic networks. We expect Nortel to complete these installations in the fourth quarter 2000 at a cost of approximately \$43,800,000, of which we have paid approximately \$18,700,000 in 2000. The remaining amount is scheduled for payment before the end of 2000 as various segments of the fiber-optic network under construction, discussed below, are completed. Touch America continues to enter into arrangements with Nortel for installations of Nortel's optical electronic equipment on Touch America's network, including an estimated \$75,000,000 of installations related to Touch America's acquisition from Qwest Communications International Inc. (Qwest) discussed below under "Investments and Acquisitions," and in Note 10, "Acquisition of Properties from Qwest."

Joint Ventures

In accordance with the agreements governing the following relationships, Touch America is committed to contribute capital at various times.

In May 2000, Touch America and Sierra Pacific Communications, a subsidiary of Sierra Pacific Resources, formed a 50-50 joint venture, named

Sierra Touch America, LLC, to construct a fiber-optic network between Sacramento and Salt Lake City. This network will make up 750 miles of the 4,300-mile build-out that Touch America is constructing in tandem with its construction of a fiber-optic network for AT&T. Sierra Touch America has begun construction of the Sacramento-Salt Lake City route and expects to complete the route in mid-2001 at an estimated cost of \$100,000,000. Touch America's portion of this estimated cost will be approximately \$83,000,000, of which it expects to recover approximately 50 percent from AT&T and other third parties. In July 2000, Touch America and Sierra Pacific Communications each contributed approximately \$1,400,000 to the joint venture, and Touch America paid approximately \$5,700,000 in construction expenditures to the joint venture. The terms of the joint venture agreement give Sierra Touch America a partial interest in the metropolitan fiber networks that Sierra Pacific Resources operates in Reno and Las Vegas.

In June 1999, Touch America and Iowa Network Services, Inc. (INS) formed Iowa Telecommunications Services, Inc. (ITS) to purchase from a third party domestic access lines connected to telephone exchanges in Iowa. However, because the emerging organizational and capital structure of ITS does not fit Touch America's growth strategy, Touch America exited from its equity position in ITS in April 2000. Under the terms of the exit agreement:

- Touch America sold its 31 percent interest in ITS to INS, and INS released Touch America from all of ITS' obligations;
- Upon the closing of the third-party purchase transaction, which occurred on June 30, 2000, INS reimbursed Touch America approximately \$7,600,000 for Touch America's cash outlays to ITS, with interest on the funds extended; and
- Touch America withdrew its \$14,000,000 letter of credit from ITS upon the closing of the third-party purchase transaction.

Investments and Acquisitions

In January 2000, Touch America signed a purchase agreement with Minnesota PCS, LP (MPCS) to acquire a 25 percent interest in MPCS' wireless telephone business, which owns Personal Communication Services (PCS) licenses in North Dakota, South Dakota, Minnesota, and Wisconsin. In accordance with the agreement, Touch America made an initial equity investment of \$2,700,000 in MPCS and agreed to loan MPCS up to \$12,000,000 in interest-bearing notes payable on October 1, 2002, of which the full \$12,000,000 had been loaned as of August 2000. In addition, Touch America has guaranteed payment of \$7,000,000 in loans owed by MPCS through the year 2007.

In March 2000, Touch America signed an agreement with Qwest to acquire Qwest's wholesale, private-line, long-distance, and other telecommunications services in US WEST's 14-state region. Touch America and Qwest closed this transaction on June 30, 2000. For more information on Touch America's acquisition, see Note 10, "Acquisition of Properties from Qwest."

NOTE 6 - LONG-TERM DEBT

On January 3, 2000, we made a payment of approximately \$10,200,000 for our share of the costs associated with the Kerr mitigation plan (Plan). This amount represented our final liability for costs under the Plan through the December 17, 1999, sale date of the electric generating assets. For further information regarding the Plan, see Note 2, "Contingencies."

Two issues of Medium-Term Notes (MTNs) were retired prior to maturity in January of 2000. On January 13, 2000, we retired \$5,000,000 of 7.25 percent Series A Secured MTNs due January 19, 2024. On January 14, 2000, we retired \$7,000,000 of 8.68 percent Series A Unsecured MTNs due February 7, 2022.

We retired at maturity \$10,000,000 of 8.80 percent Series A Unsecured MTNs on February 22, 2000.

On April 13, 2000, we retired prior to maturity \$25,000,000 of our 7.5 percent First Mortgage Bonds (Bonds) due April 1, 2001.

On April 25, 2000, we offered to purchase any or all of the following series of our outstanding debt: 8.95 percent Bonds due February 1, 2022; 7.33 percent Secured MTNs due April 15, 2025; 8.11 percent Secured MTNs due January 25, 2023; 7.00 percent Bonds due March 1, 2005; and 8.25 percent Bonds due February 1, 2007. The total amount outstanding for these issues was \$190,000,000 as of April 25, 2000. On May 24, 2000, we retired \$182,700,000 of this amount, as follows:

- \$48,500,000 of 8.95 percent Bonds due February 1, 2022;
- \$20,000,000 of 7.33 percent Secured Series A MTNs due April 15, 2025;
- \$15,000,000 of 8.11 percent Secured Series A MTNs due January 25, 2023;
- \$44,600,000 of 7.00 percent Bonds due March 1, 2005; and
- \$54,600,000 of 8.25 percent Bonds due February 1, 2007.

In addition, we retired at maturity \$20,000,000 of 7.20 percent Series A Secured MTNs on June 1, 2000.

These debt retirements were made from the proceeds received from the sale of the electric generating assets.

As part of the Tier II rate filing discussed in Note 1, "Deregulation, Regulatory Matters, Sale of Electric Generating Assets, and Proposed Divestiture of Energy Businesses," we indicated our intention to retire approximately \$266,000,000 of debt. The expenses associated with the debt retirements were estimated at approximately \$20,000,000. With all retirements of MTNs and Bonds discussed above, the actual amount of debt retired (including the retirement in 1999 of \$15,000,000 of 7.875 percent Series B Unsecured MTNs due December 23, 2026) was slightly less than \$265,000,000 and the associated expenses were approximately \$9,300,000.

On April 4, 2000, a \$100,000,000 Revolving Credit Agreement associated with some of our nonutility operations terminated, with no amount outstanding.

Altana Exploration Ltd., our wholly owned Canadian subsidiary, made payments of approximately \$10,400,000 in United States dollars (approximately \$15,300,000 Canadian dollars) during the first six months of 2000 pursuant to its revolving line of credit, resulting in a balance outstanding at June 30, 2000 of approximately \$6,700,000 United States dollars (approximately \$10,000,000 Canadian dollars).

NOTE 7 - COMPREHENSIVE INCOME

For the six months ended June 30, 2000 and 1999, our only item of other comprehensive income was foreign currency translation adjustments of the assets and liabilities of our foreign subsidiaries. These adjustments resulted in decreases to retained earnings of \$1,789,000 in 2000, and increases to retained earnings of \$2,262,000 in 1999. No current income tax effects resulted from the adjustments, nor do we expect there to be any net income effects until we sell a foreign subsidiary. For the six months ended June 30, 2000, comprehensive income was approximately \$65,907,000, as compared to comprehensive income of approximately \$61,335,000 for the six months ended June 30, 1999.

NOTE 8 - INFORMATION ON INDUSTRY SEGMENTS:

Our utility operations purchase, transmit, and distribute electricity and natural gas. With the sale of our electric generating assets other than Milltown Dam, we no longer are primarily engaged in regulated electric generation. In our nonutility businesses, our telecommunications operation designs, develops, constructs, operates, maintains, and manages a fiber-optic network and wireless facilities; it also sells long-distance, Internet, and private-line services and equipment. In other nonutility operations, we mine and sell coal and lignite; manage long-term power sales, and develop and invest in independent power projects and other energy-related businesses; and explore for, develop, produce, process, and sell crude oil and natural gas. We also trade crude oil, natural gas, and natural gas liquids.

Identifiable assets of each industry segment are principally those assets used in our operation of those industry segments. Corporate assets are principally cash and cash equivalents and temporary investments.

We consider segment information for foreign operations immaterial.

NOTE 8 - INFORMATION ON INDUSTRY SEGMENTS

Operations Information

Six Months Ended
June 30, 2000
(Thousands of Dollars)

UTILITY

	Electric	Natural Gas
Sales to unaffiliated customers.....	\$ 203,065	\$ 66,954
Earnings from unconsolidated investments...	-	-
Intersegment sales.....	1,890	235
Pretax operating income	18,270	11,367
Capital expenditures.....	14,328	1,897
Identifiable assets.....	1,052,310	333,681

NONUTILITY

	Tele- Communications	Coal ^(c)	Independent Power ^(d)
Sales to unaffiliated customers.....	\$ 52,639	\$ 104,767	\$ 33,681
Earnings from unconsolidated investments...	(265)	-	43,909
Intersegment sales.....	727	6,040	264
Pretax operating income	12,242	12,608	40,215
Capital expenditures.....	250,520 ^(a)	8,115	886
Identifiable assets.....	545,767 ^(b)	242,820	70,109

NONUTILITY (continued)

	Oil and Natural Gas	Other
Sales to unaffiliated customers.....	\$ 187,690	\$ 6,491
Earnings from unconsolidated investments...	-	-
Intersegment sales.....	9,725	1,995
Pretax operating income (loss)	17,583	(450)
Capital expenditures.....	15,600	10,632
Identifiable assets.....	300,253	62,504

CORPORATE

Capital expenditures.....	\$ 11,917
Identifiable assets.....	77,312

RECONCILIATION TO CONSOLIDATED

	Segment Total	Adjustments ^(e)	Consolidated Total
Sales to unaffiliated customers.....	\$ 655,287	-	\$ 655,287
Earnings from unconsolidated investments...	43,644	-	43,644
Intersegment sales.....	20,876	(20,876)	-
Pretax operating income	111,835	-	111,835
Capital expenditures.....	313,895	-	313,895
Identifiable assets.....	2,684,756	-	2,684,756

^(a) This amount includes approximately \$205,900,000 related to the Qwest acquisition.

^(b) This amount includes approximately \$145,600,000 of intangible assets related to the Qwest acquisition, which may be allocated among various classifications pending an appraisal by an independent third party.

^(c) The loss of revenues pursuant to one contract with a single customer would have a material adverse effect on the segment.

^(d) The loss of revenues pursuant to contracts with two customers would have a material adverse effect on the segment.

^(e) The amounts indicated include certain eliminations between the business segments.

Operations Information

Six Months Ended	
June 30, 1999	
(Thousands of Dollars)	

UTILITY

	Electric	Natural Gas
Sales to unaffiliated customers.....	\$ 221,977	\$ 62,735
Earnings from unconsolidated investments...	-	-
Intersegment sales.....	6,468	336
Pretax operating income	56,447	11,078
Capital expenditures.....	22,160	2,518
Identifiable assets.....	1,683,778	390,590

NONUTILITY

	Tele-Communications	Coal	Independent Power ^(a)
Sales to unaffiliated customers.....	\$ 41,129	\$ 92,217	\$ 36,968
Earnings from unconsolidated investments...	2,100	-	9,464
Intersegment sales.....	354	19,740	663
Pretax operating income	14,136	16,635	10,893
Capital expenditures.....	31,307	1,932	207
Identifiable assets.....	210,984	234,691	99,483

NONUTILITY (continued)

	Oil and Natural Gas	Other
Sales to unaffiliated customers.....	\$ 145,554	\$ 19,124
Earnings from unconsolidated investments...	-	-
Intersegment sales.....	8,312	1,002
Pretax operating income (loss).....	5,743	(2,654)
Capital expenditures.....	16,884	12
Identifiable assets.....	310,000	67,638

CORPORATE

Capital expenditures.....	\$ 1,121
Identifiable assets.....	19,455

RECONCILIATION TO CONSOLIDATED

	Segment Total	Adjustments ^(b)	Consolidated Total
Sales to unaffiliated customers.....	\$ 619,704	-	\$ 619,704
Earnings from unconsolidated investments...	11,564	-	11,564
Intersegment sales.....	36,875	\$ (36,875)	-
Pretax operating income	112,278	-	112,278
Capital expenditures.....	76,141	-	76,141
Identifiable assets.....	3,016,619	-	3,016,619

^(a) The loss of revenues pursuant to contracts with two customers would have a material adverse effect on the segment.

^(b) The amounts indicated include certain eliminations between the business segments.

Operations Information

Quarter Ended	
June 30, 2000	
(Thousands of Dollars)	

UTILITY

	Electric	Natural Gas
Sales to unaffiliated customers.....	\$ 101,574	\$ 22,160
Earnings from unconsolidated investments...	-	-
Intersegment sales.....	320	32
Pretax operating income (loss).....	5,999	(685)
Capital expenditures.....	8,721	4,931
Identifiable assets.....	1,052,310	333,681

NONUTILITY

	Tele-Communications	Coal ^(c)	Independent Power ^(d)
Sales to unaffiliated customers.....	\$ 28,513	\$ 47,486	\$ 15,932
Earnings from unconsolidated investments...	(867)	-	38,209
Intersegment sales.....	419	2,102	64
Pretax operating income.....	5,168	4,601	35,556
Capital expenditures.....	233,590 ^(a)	6,325	825
Identifiable assets.....	545,767 ^(b)	242,820	70,109

NONUTILITY (continued)

	Oil and Natural Gas	Other
Sales to unaffiliated customers.....	\$ 82,275	\$ (1,215)
Earnings from unconsolidated investments...	-	-
Intersegment sales.....	4,360	471
Pretax operating income	8,633	32
Capital expenditures.....	6,605	8,706
Identifiable assets.....	300,253	62,504

CORPORATE

Capital expenditures.....	\$ 6,984
Identifiable assets.....	77,312

RECONCILIATION TO CONSOLIDATED

	Segment Total	Adjustments ^(e)	Consolidated Total
Sales to unaffiliated customers.....	\$ 296,725	-	\$ 296,725
Earnings from unconsolidated investments...	37,342	-	37,342
Intersegment sales.....	7,768	(7,768)	-
Pretax operating income.....	59,304	-	59,304
Capital expenditures.....	276,687	-	276,687
Identifiable assets.....	2,684,756	-	2,684,756

^(a) This amount includes approximately \$205,900,000 related to the Qwest acquisition.

^(b) This amount includes approximately \$145,600,000 of intangible assets related to the Qwest acquisition, which may be allocated among various classifications pending an appraisal by an independent third party.

^(c) The loss of revenues pursuant to one contract with a single customer would have a material adverse effect on the segment.

^(d) The loss of revenues pursuant to contracts with two customers would have a material adverse effect on the segment.

^(e) The amounts indicated include certain eliminations between the business segments.

Operations Information

Quarter Ended	
June 30, 1999	
(Thousands of Dollars)	

UTILITY

	Electric	Natural Gas
Sales to unaffiliated customers.....	\$ 105,443	\$ 22,390
Earnings from unconsolidated investments...	-	-
Intersegment sales.....	2,778	137
Pretax operating income	26,773	938
Capital expenditures.....	14,136	4,933 ^(a)
Identifiable assets.....	1,683,778	390,590

NONUTILITY

	Tele-Communications	Coal ^(a)	Independent Power ^(b)
Sales to unaffiliated customers.....	\$ 21,354	\$ 48,779	\$ 18,734
Earnings from unconsolidated investments...	677	-	4,131
Intersegment sales.....	126	9,836	425
Pretax operating income	7,393	8,889	4,892
Capital expenditures.....	25,767	298	-
Identifiable assets.....	210,984	234,691	99,483

NONUTILITY (continued)

	Oil and Natural Gas	Other
Sales to unaffiliated customers.....	\$ 76,745	\$ 11,247
Earnings from unconsolidated investments...	-	-
Intersegment sales.....	3,912	561
Pretax operating income (loss).....	2,302	(822)
Capital expenditures.....	6,570	-
Identifiable assets.....	310,000	67,638

CORPORATE

Capital expenditures.....	\$ 712
Identifiable assets.....	19,455

RECONCILIATION TO CONSOLIDATED

	Segment Total	Adjustments ^(c)	Consolidated Total
Sales to unaffiliated customers.....	\$ 304,692	-	\$ 304,692
Earnings from unconsolidated investments...	4,808	-	4,808
Intersegment sales.....	17,775	\$ (17,775)	-
Pretax operating income	50,365	-	50,365
Capital expenditures.....	52,416	(39)	52,377
Identifiable assets.....	3,016,619	-	3,016,619

^(a) Revenues from sales under one contract to Reliant Energy amounted to \$30,316,000 for the three-month period ended June 30, 1999.

^(b) The loss of revenues pursuant to contracts with two customers would have a material adverse effect on the segment.

^(c) The amounts indicated include certain eliminations between the business segments.

NOTE 9 - COMMON STOCK

STOCK SPLIT

On June 22, 1999, the Board of Directors approved a two-for-one split of our outstanding common stock. As a result of the split, which was effective August 6, 1999, for all shareholders of record on July 16, 1999, 55,099,015 outstanding shares of common stock were converted to 110,198,030 outstanding shares of common stock. We have retroactively applied the split to all periods presented.

SHARE REPURCHASE PROGRAM

In 1998, the Board of Directors authorized a share-repurchase program over the next five years to repurchase up to 20,000,000 shares (approximately 18 percent of our then outstanding common stock) on the open market or in privately negotiated transactions. As of August 7, 2000, we had 105,630,296 common shares outstanding. The number of shares to be purchased and the timing of the purchases will be based on the level of cash balances, general business conditions, and other factors, including alternative investment opportunities.

Subsequent to this authorization, we entered into a Forward Equity Acquisition Transaction (FEAT) program with a bank that committed to purchase shares on our behalf. Under the terms of the program, the amount owed to the bank and the number of shares held by the bank cannot exceed certain limits. In March 2000, these limits were amended and now are \$125,000,000 and 2,500,000 shares. The expiration date of the program is August 1, 2001. Until that date, when all transactions must be settled, we can elect to fully or partially settle either on a full physical (cash) or a net share basis. A full physical settlement would be the purchase of shares from the bank for cash at the bank's average purchase price plus interest costs less dividends. A net share settlement would be the exchange of shares between the parties so that the bank receives shares with value equivalent to its original purchase price plus interest costs less dividends. Only at the time that the transactions are settled can our capital or outstanding stock be affected, and settlement has no effect on results of operations.

In December 1999, when the limits described above were \$200,000,000 and 8,000,000 shares, we used proceeds from the sale of our generation assets to acquire 4,682,100 shares of our stock under the FEAT program. The purchase of these shares averaged approximately \$30.94 per share and ranged from \$27.05 per share to \$33.52 per share for a total cost of \$144,872,000. We have reflected the shares purchased as treasury stock on the Consolidated Balance Sheet.

No additional shares were acquired under the program from January 1, 2000 through July 31, 2000. From August 1, 2000, through August 9, 2000, the bank had acquired for us 610,000 shares of our stock under the FEAT program. The average price, including commissions, was approximately \$30.51 per share, with prices ranging from \$29.78 per share to \$31.67 per share, for a total cost of approximately \$18,600,000.

NOTE 10 - ACQUISITION OF PROPERTIES FROM QWEST

On June 30, 2000, in accordance with a previously executed stock purchase agreement, we acquired Qwest's wholesale, private-line, long-distance, and other telecommunications services in US WEST's fourteen-state region associated with Qwest's interLATA businesses for approximately \$206,000,000, subject to certain adjustments. We estimate that Touch America's related capital expenditures, mainly to install optronics on new routes, will be an additional

\$75,000,000. The fourteen-state region covers approximately 250,000 customer accounts for voice, data, and video services. Touch America also acquired a fiber-optic network of 1,800 route miles and associated optronics and switches that will connect to Touch America's existing fiber-optic network. As a result of the acquisition, Touch America employed 173 of Qwest's former marketing representatives in the fourteen-state region.

The sources of funds for this transaction were a combination of approximately \$147,000,000 in internal funds and approximately \$59,000,000 in short-term borrowings from various external sources.

Our June 30, 2000 Consolidated Balance Sheet includes approximately \$60,000,000 of net nonutility plant and approximately \$146,000,000 of intangible assets related to the Qwest acquisition. Because the transaction closed on June 30, our Consolidated Statements of Income do not include any depreciation or amortization expense associated with the properties acquired. An independent third party is presently appraising the value of the properties acquired. When this appraisal is complete, we will adjust our allocation of the purchase price among the various balance sheet classifications, if necessary.

As a result of the Qwest acquisition, we will file audited historical and unaudited pro forma financial information with the Securities and Exchange Commission (SEC) on or before September 15, 2000.

NOTE 11 - SHORT-TERM BORROWING

At June 30, 2000, we had committed lines of credit consisting of \$190,000,000 and uncommitted lines of \$90,000,000. Facility/commitment fees on the committed lines of credit are not significant. We have the ability to issue up to \$95,000,000 of commercial paper based on the total amount of unused committed lines of credit and revolving credit agreements.

At June 30, 2000, we had notes payable to banks for \$65,000,000 at an average annual interest rate of approximately 7.4 percent.

On June 29, 2000, we developed a \$200,000,000 90-Day Credit Agreement for use in our telecommunications operations. This agreement expires on September 26, 2000.

NOTE 12 - EARNINGS PER SHARE OF COMMON STOCK

We compute basic net income per share of common stock for each year based upon the weighted average number of common shares outstanding. In accordance with Statement of Financial Accounting Standards (SFAS) No. 128, "Earnings per Share," diluted net income per share of common stock reflects the potential dilution that would occur if securities or other contracts to issue common stock were exercised or converted into common stock or resulted in the issuance of common stock that shared in our earnings.

NOTE 13 - NEW ACCOUNTING PRONOUNCEMENTS

In June 2000, the SEC issued Staff Accounting Bulletin (SAB) No. 101B, "Second Amendment: Revenue Recognition in Financial Statements", which delays the implementation date of SAB No. 101 until no later than the fourth quarter 2000 for companies with fiscal years beginning after December 15, 1999. We do not expect the adoption of SAB No. 101 to have a material effect on our consolidated financial position or results of operations.

SFAS Nos. 133, 137, and 138

In June 1998, the Financial Accounting Standards Board (FASB) issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." SFAS No. 133 expands the definition of a derivative and requires that all derivative instruments be recorded on an entity's balance sheet at fair value. In July 1999, the FASB issued SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities: Deferral of the Effective Date of FASB Statement No. 133." SFAS No. 137 delays for one year the effective date of SFAS No. 133, meaning that we are not required to adopt SFAS No. 133 until January 1, 2001. In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," which amends some accounting and reporting standards of SFAS No. 133, but not the January 2001 effective date. We are presently evaluating how SFAS No. 138 may affect us.

We expect to complete the sales of our energy businesses within six to twelve months from the end of the first quarter 2000, and we expect to sell our unregulated oil and natural gas businesses - including MPT&M - before January 1, 2001. While we have begun a review of our commodity purchase and sale agreements to evaluate exposure to potential embedded derivatives, we do not expect the adoption of SFAS No. 137, as amended by SFAS No. 138, to have a material effect on our consolidated financial position, results of operations, or cash flows.

ITEM 2 - MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Please read the following discussion in conjunction with the statements included in our Annual Report on Form 10-K for the year ended December 31, 1999 at Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations."

Warnings About Forward-Looking Statements

This Quarterly Report on Form 10-Q may contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements are qualified by and should be read together with the cautionary statements and important factors included in our Annual Report on Form 10-K for the year ended December 31, 1999. See Part I, "Warnings About Forward-Looking Statements."

We are including the following cautionary statements to make applicable and take advantage of the safe-harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by us, or on our behalf, in this Form 10-Q. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance and underlying assumptions, and other statements, which are statements other than those of historical fact. Forward-looking statements may be identified, without limitation, by the use of the words "anticipates," "estimates," "expects," "intends," "believes," and similar expressions. We disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date that we file this Form 10-Q.

Forward-looking statements that we make are subject to risks and uncertainties that could cause actual results or events to differ materially from those expressed in, or implied by, the forward-looking statements. These forward-looking statements include, among others, statements concerning our revenue and cost trends, cost recovery, cost-reduction strategies and anticipated outcomes, pricing strategies, planned capital expenditures, financing needs and availability, and changes in the utility and telecommunication industries and other industries in which we operate. Investors or other readers of the forward-looking statements are cautioned that these statements are not a guarantee of future performance and that the forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, the statements. Some, but not all, of the risks and uncertainties include:

- General economic and weather conditions in the areas in which we have operations;
- Competitive factors and the effects of restructuring in the electric, natural gas, and telecommunications industries;
- Sanctity and enforceability of contracts;
- Market prices;
- Environmental laws and policies and federal and state regulatory and legislative actions;
- Drilling successes in oil and natural gas operations;
- Changes in foreign trade and monetary policies;
- Laws and regulations related to foreign operations;
- Tax rates and policies and interest rates; and
- Changes in accounting principles or the application of such principles.

Strategy

We are focused on growing Touch America's revenues and earnings as demonstrated by the expansion of our fiber-optic network, which we expect to span more than 26,000 miles by the end of 2001. In pursuing this strategy, we will continue to investigate different approaches, including asset purchases and sales, the issuance of securities, and other transactions that may materially affect our results of operations, liquidity, and capital resources.

We expect to expand Touch America's business, leveraging off of the fiber network and selling a broad array of communications products and services primarily focused on wholesale and commercial markets. We expect Touch America to focus its efforts initially in the western United States, but to expand nationally as the network is completed. For a discussion of how we intend to use net proceeds from the sales of our energy businesses, see the "Proposed Divestiture of Energy Businesses" section of Note 1, "Deregulation, Regulatory Matters, Sale of Electric Generating Assets, and Proposed Divestiture of Energy Businesses."

Results of Operations

The following discussion describes significant events or trends that have had an effect on our operations or which we expect to have an effect on our future operating results. We have adjusted all 1999 share and earnings-per-share information to reflect the two-for-one stock split effective August 6, 1999.

For the Six Months Ended June 30, 2000 and 1999:

Net Income Per Share of Common Stock (Basic)

Year-to-date earnings were \$0.62 per share, \$0.10 per share more than year-to-date 1999 earnings of \$0.52 per share, an increase of 19 percent. Utility earnings were \$0.06 per share, compared with \$0.18 per share last year, a decrease of 67 percent. Nonutility earnings were \$0.56 per share, up \$0.22 per share, or 65 percent, from the \$0.34 per share figure of a year earlier.

Utility Operating Income

- Income from electric utility operations decreased approximately \$38,200,000 compared with the six months ended June 30, 1999, mainly because of the effects of the fourth quarter 1999 sale of our electric generating assets and the voluntary rate reduction that became effective on February 2, 2000.
- Income from our natural gas utility operations increased approximately \$300,000 during the period mainly because of increases in rates that became effective on December 10, 1999 and April 1, 2000.

Nonutility Operating Income

- Income from our telecommunications operations decreased approximately \$1,900,000 compared with the first six months of 1999, principally as a result of decreased earnings from unconsolidated investments and increased operating expenses.
- Income from our coal operations decreased approximately \$4,000,000 during the period principally because of lower revenues - resulting from a decrease in tons sold as a result of scheduled maintenance and unplanned outages at the generating plants in Colstrip, Montana and

scheduled maintenance at the generating plants in Jewett, Texas - and higher reclamation, maintenance, and diesel fuel costs.

- Income from our independent power operations increased approximately \$29,300,000 during the period. On June 30, 2000, Continental Energy Services sold its equity interest in a partnership that owned the Brazos project in Cleburne, Texas. As a result of this transaction, Continental Energy recorded a pretax gain of approximately \$34,300,000.
- Oil and natural gas operating income increased approximately \$11,800,000 during the period, resulting from significantly higher commodity prices.

For comparative purposes, the following table shows consolidated basic net income per share by principal business segment.

	Six Months Ended	
	June 30, 2000	June 30, 1999
Utility Operations	\$ 0.06	\$ 0.18
Nonutility Operations	0.56	0.34
Consolidated	<u>\$ 0.62</u>	<u>\$ 0.52</u>

UTILITY OPERATIONS

	For Six Months Ended	
	June 30, 2000	June 30, 1999
	(Thousands of Dollars)	
<u>ELECTRIC UTILITY:</u>		
REVENUES:		
Revenues.....	\$ 203,065	\$ 221,977
Intersegment revenues.....	1,890	6,468
	<u>204,955</u>	<u>228,445</u>
EXPENSES:		
Power supply.....	105,856	69,565
Transmission and distribution.....	19,447	22,408
Selling, general, and administrative.....	24,162	27,563
Taxes other than income taxes.....	18,825	25,289
Depreciation and amortization.....	18,395	27,173
	<u>186,685</u>	<u>171,998</u>
INCOME FROM ELECTRIC OPERATIONS.....	18,270	56,447
<u>NATURAL GAS UTILITY:</u>		
REVENUES:		
Revenues (other than gas supply cost revenues).....	44,687	41,621
Gas supply cost revenues.....	22,267	21,114
Intersegment revenues.....	235	336
	<u>67,189</u>	<u>63,071</u>
EXPENSES:		
Gas supply costs.....	22,267	21,114
Other production, gathering, and exploration.....	532	1,134
Transmission and distribution.....	7,795	7,303
Selling, general, and administrative.....	13,601	10,532
Taxes other than income taxes.....	6,847	7,270
Depreciation, depletion, and amortization.....	4,780	4,640
	<u>55,822</u>	<u>51,993</u>
INCOME FROM NATURAL GAS OPERATIONS.....	11,367	11,078
<u>INTEREST EXPENSE AND OTHER INCOME:</u>		
Interest.....	23,228	28,880
Distributions on mandatorily redeemable preferred securities of subsidiary trusts.....	2,746	2,746
Other income - net.....	(11,575)	(2,318)
	<u>14,399</u>	<u>29,308</u>
INCOME BEFORE INCOME TAXES.....	15,238	38,217
INCOME TAXES.....	7,302	16,669
DIVIDENDS ON PREFERRED STOCK.....	1,845	1,845
UTILITY NET INCOME AVAILABLE FOR COMMON STOCK.....	\$ 6,091	\$ 19,703

UTILITY OPERATIONS

Electric Utility

With the sale of our electric generating assets, we reduced our utility net plant by approximately \$497,000,000. Since we no longer earn an equity rate of return on those assets, we experienced a decline in utility earnings, as expected.

Prior to the sale, revenues covered the costs of operating the generating plants, taxes and interest, and earned a return on our shareholders' investment. Since the sale, we continue to bill for energy supply, but now these revenues cover the costs to purchase power to serve our core customers. These costs no longer fluctuate based on actual operating results, but are fixed based on an allocated cost-of-service price. While revenues from sales to our core customers were not affected by the sale, we now pay the profit component of revenues - which previously represented the return on our shareholders' investment - as part of purchased power expenses. Buyback contracts allow us to purchase power necessary to serve our core customers through the transition period ending in 2002. The price in the buyback contracts, \$22.25/MWh, represents our net fully allocated costs of service in current rates, replacing operations and maintenance expense, property tax expense, depreciation expense, and return on investment. We reflect the costs of purchased power under the buyback contracts in operating expenses as power supply expenses.

As discussed above in the "Regulatory Matters" section of Note 1, "Deregulation, Regulatory Matters, Sale of Electric Generating Assets, and Proposed Divestiture of Energy Businesses we filed a request for a rate increase with the PSC in August 2000. In January 2000, as a result of proceeds from the sale of our electric generating assets exceeding the book value of those assets, we filed a rate reduction request with the PSC for approximately \$16,700,000 annually. This rate reduction, which was voluntary pending a final determination by the PSC of our Tier II issues, became effective on February 2, 2000. For additional information on the Tier II filing, see Note 4, "Deregulation and Regulatory Matters," of our 1999 Annual Report on Form 10-K.

The following table categorizes revenues and volumes into General Business Revenues, Sales To Other Utilities, Other, and Intersegment. It also shows Bundled Revenues and Distribution Only Revenues separately for General Business Revenues. While we no longer supply the electricity for customers who have chosen other commodity suppliers, we continue to earn transmission and distribution revenues for moving their electricity across our transmission and distribution lines. We reflect transmission revenues as Other Revenues and distribution revenues as Distribution Only Revenues. We expect Other revenues to continue to increase as additional customers move to choice. For customers who have not chosen other suppliers, Bundled Revenues reflect fully bundled rates for supplying, transmitting, and distributing electricity. We expect these revenues to continue to decrease as additional customers move to choice.

	Revenues					
	Power Supply Expenses			Volumes		
	(Thousands of Dollars)			(Thousands of MWh)		
	6/30/00	6/30/99		6/30/00	6/30/99	
REVENUES:						
GENERAL BUSINESS BUNDLED REVENUES:						
Residential.....	\$ 61,813	\$ 64,861	(5)%	960	974	(1)%
Small commercial, small industrial, and government and municipal.....	70,457	78,610	(10)%	1,170	1,288	(9)%
Large commercial, large industrial....	19,698	23,248	(15)%	532	743	(28)%
Irrigation and street lighting.....	6,425	6,169	4 %	65	45	44 %
Total	158,393	172,888	(8)%	2,727	3,050	(11)%
GENERAL BUSINESS DISTRIBUTION ONLY REVENUES:						
Residential.....	118	-	-	4	-	-
Small commercial, small industrial, and government and municipal.....	2,322	724	221 %	139	40	248 %
Large commercial, large industrial....	3,256	3,943	(17)%	954	577	65 %
Total	5,696	4,667	22%	1,097	617	78 %
TOTAL GENERAL BUSINESS REVENUES	164,089	177,555	(8)%	3,824	3,667	4 %
SALES TO OTHER UTILITIES.....	25,920	34,542	(25)%	655	1,781	(63)%
OTHER.....	13,056	9,880	32 %	-	-	-
INTERSEGMENT.....	1,890	6,468	(71)%	-	58	-
TOTAL	\$ 204,955	\$ 228,445	(10)%	4,479	5,506	(19)%
POWER SUPPLY EXPENSES:						
Hydroelectric.....	-	10,731	-	-	2,000	-
Steam.....	-	26,994	-	-	2,249	-
Purchased power and other.....	105,856	31,840	232%	3,899	924	322 %
Total	\$ 105,856	\$ 69,565	52%	3,899	5,173	(25)%
Dollars per MWh	\$ 27.15	\$ 13.45				

Income from electric utility operations decreased approximately \$38,200,000, or 68 percent compared to the six months ended June 30, 1999, primarily because of the effects of the sale of our electric generating assets and the voluntary rate reduction discussed above.

Revenues: Revenues decreased approximately \$23,500,000 compared with year-to-date 1999, primarily due to the effects of the following items:

- **General Business:** These revenues decreased approximately \$13,500,000, mainly from the voluntary rate reduction discussed above, customers continuing to choose other suppliers, and a weather-related reduction in volumes sold resulting from weather 10 percent warmer than normal and 3 percent warmer than in 1999. An increase in general business prices to recover the cost of public-purpose programs in accordance with the Universal System Benefits Charge requirements of the Electric Act mitigated the effects of decreased revenues. The effect on earnings of the volume decreases from warmer weather and customer choice were partially offset by corresponding decreases in purchased power costs.
- **Sales to Other Utilities:** These revenues decreased approximately \$8,600,000 because, with the sale of our generating assets, we no longer sell surplus generation in the secondary markets. However, our affiliate, The Montana Power Trading & Marketing Company (MPT&M), transferred to the utility an index-based purchase contract that we have been using to supply power to a large industrial customer since the sale of our generating assets. We have been selling all power purchased under the index-based contract not used by our industrial customer in the secondary market at significantly higher prices.
- **Other:** These revenues increased approximately \$3,200,000 mainly from

transmitting energy for PPL Montana and customers who chose other suppliers. We reflect transmission revenues from customers who are not supplied by us as Other revenues in the table above. Prior to the generation sale, the energy transmitted for PPL Montana was generated by us and sold by MPT&M in the secondary markets, with MPT&M using our lines to transmit the energy across our service territory. The transmission of this energy was reflected as Intersegment revenues in the table above. We report transmission revenues from customers who have not chosen other suppliers as General Business revenues.

- **Intersegment:** These revenues decreased approximately \$4,600,000 principally because MPT&M no longer engages in secondary-market sales requiring the use of our lines to transmit surplus generation. As discussed above, an increase in Other revenues from transmitting energy for PPL Montana partially offset this decrease.

Expenses: Power-supply expenses increased; transmission and distribution expenses decreased; selling, general, and administrative (SG&A) expenses decreased; taxes other than income taxes decreased; and depreciation and amortization expenses decreased for the six months ended June 30, 2000, when compared with the six months ended June 30, 1999. These expenses changed because of the effects of the following items, most of which, as discussed, were attributable to the generation sale:

- Power-supply expenses increased approximately \$36,300,000, mainly because of increased purchased power costs required to supply electric energy to our core customers, along with a higher average price for wholesale power under the index-based purchase contract mentioned above. The increase was partially offset by a decrease in purchased power resulting from warmer weather and customers choosing other suppliers. As discussed above, the increase in purchased power costs attributable to the generation sale is recoverable in rates.
- Transmission and distribution wheeling expenses decreased approximately \$3,000,000 primarily because, as discussed above, we are no longer selling surplus generation in the secondary markets. As a result, we did not incur the costs associated with using other utilities' lines outside our service territory to transmit this energy.
- SG&A expenses decreased approximately \$3,400,000 mainly due to a decrease in regulatory amortizations and pension expense, both related to the generation sale. Increased energy-efficiency and public-purpose program costs in compliance with the Electric Act partially offset these decreases. In accordance with the Electric Act, we collect the costs associated with the energy-efficiency and public-purpose programs through a separate component of rates.
- Taxes other than income taxes and depreciation expense decreased a total of approximately \$15,200,000 as a result of the sale of most of our generation plant.

Regulatory: For more information on our August 2000 filing with the PSC, in which we are seeking increased annual electric revenues, see Note 1, "Deregulation, Regulatory Matters, Sale of Electric Generating Assets, and Proposed Divestiture of Energy Businesses," under "Regulatory Matters."

Natural Gas Utility

The following table categorizes revenues and volumes into General Business Revenues, Sales to Other Utilities, Transportation, and Other.

	Revenues			Volumes*		
	(Thousands of Dollars)			(Thousands of Dkt)		
	6/30/00	6/30/99		6/30/00	6/30/99	
REVENUES:						
Residential	\$ 39,026	\$ 36,365	7 %	6,580	7,026	(6)%
Small commercial, small industrial, and government and municipal	18,928	17,028	11 %	3,203	3,334	(4)%
General business revenues	57,954	53,393	9 %	9,783	10,360	(6)%
Less: Gas supply cost revenues (GSC)	22,267	21,114	5 %	-	-	-
General business revenues without GSC	35,687	32,279	11 %	9,783	10,360	(6)%
Sales to other utilities	480	459	5 %	158	171	(8)%
Transportation	8,050	8,011	-	11,795	12,280	(4)%
Other	470	872	(46)%	-	-	-
Total	\$ 44,687	\$ 41,621	7 %	21,736	22,811	(5)%

*A Dekatherm measures the heat used and is the basis of how we bill our customers.

Income from natural gas operations increased approximately \$300,000, or 3 percent, when compared with the six months ended June 30, 1999.

Revenues: Revenues increased approximately \$4,100,000, principally due to increased General Business revenues resulting from increased rates and customer growth. Weather-related decreases in volumes sold reduced the effects of the increase. All of our former Large Industrial and Large Commercial customers have chosen other commodity suppliers and, while we no longer supply the natural gas for those customers, we still earn transportation revenues from moving their natural gas through our pipelines. We reflect these revenues as Transportation revenues in the table above.

Expenses: Operating expenses - consisting of gas supply costs; other production, gathering, and exploration expenses; transmission and distribution expenses; and SG&A expenses - increased approximately \$4,100,000 chiefly because of increased SG&A expenses resulting mainly from increased incentive-compensation accruals and miscellaneous administrative items. Taxes other than income taxes decreased approximately \$400,000 principally due to our June 2000 settlement of a property tax dispute with the Montana Department of Revenue. As a result of this settlement, we reduced property tax expense by approximately \$500,000.

Regulatory: In August 1999, we filed a natural gas rate case with the PSC that resulted in an interim increase of \$7,600,000 effective on December 10, 1999, and an additional increase of \$2,800,000 that became effective on April 1, 2000. For more information on our August 2000 filing with the PSC, in which we are seeking increased annual natural gas revenues, see Note 1, "Deregulation, Regulatory Matters, Sale of Electric Generating Assets, and Proposed Divestiture of Energy Businesses," under "Regulatory Matters."

Utility Interest Expense and Other Income

Interest expense decreased approximately \$5,700,000 with the net retirement of long-term debt in late 1999 and early 2000 and the decrease in interest expense related to the Kerr Project mitigation liability, which was reduced with our sale of the generation assets. Other Income - Net increased approximately \$9,300,000 primarily because of interest income earned on the higher cash balances held in 2000 compared to 1999.

NONUTILITY OPERATIONS

For Six Months Ended	
June 30,	June 30,
2000	1999
(Thousands of Dollars)	

TELECOMMUNICATIONS:

REVENUES:

Revenues.....	\$ 52,639	\$ 41,129
Earnings from unconsolidated investments.....	(265)	2,100
Intersegment revenues.....	727	354
	<u>53,101</u>	<u>43,583</u>

EXPENSES:

Operations and maintenance.....	24,383	17,828
Selling, general, and administrative.....	8,646	5,670
Taxes other than income taxes.....	2,290	1,425
Depreciation and amortization.....	5,540	4,524
	<u>40,859</u>	<u>29,447</u>

INCOME FROM TELECOMMUNICATIONS OPERATIONS.....	12,242	14,136
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COAL:

REVENUES:

Revenues.....	104,767	92,217
Intersegment revenues.....	6,040	19,740
	<u>110,807</u>	<u>111,957</u>

EXPENSES:

Operations and maintenance.....	70,904	68,862
Selling, general, and administrative.....	10,353	9,762
Taxes other than income taxes.....	13,132	13,014
Depreciation, depletion, and amortization.....	3,810	3,684
	<u>98,199</u>	<u>95,322</u>

INCOME FROM COAL OPERATIONS.....	12,608	16,635
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INDEPENDENT POWER:

REVENUES:

Revenues.....	33,681	36,968
Earnings from unconsolidated investments.....	43,909	9,464
Intersegment revenues.....	264	663
	<u>77,854</u>	<u>47,095</u>

EXPENSES:

Operations and maintenance.....	32,118	31,911
Selling, general, and administrative.....	2,705	1,811
Taxes other than income taxes.....	1,147	919
Depreciation and amortization.....	1,669	1,561
	<u>37,639</u>	<u>36,202</u>

INCOME FROM INDEPENDENT POWER OPERATIONS.....	\$ 40,215	\$ 10,893
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NONUTILITY OPERATIONS (continued)

	For Six Months Ended	
	June 30, 2000	June 30, 1999
	(Thousands of Dollars)	
<u>OIL AND NATURAL GAS:</u>		
REVENUES:		
Revenues	\$ 187,690	\$ 145,554
Intersegment revenues	9,725	8,312
	<u>197,415</u>	<u>153,866</u>
EXPENSES:		
Operations and maintenance	152,305	125,067
Selling, general, and administrative	10,486	8,960
Taxes other than income taxes	3,601	2,577
Depreciation, depletion, and amortization	13,440	11,519
	<u>179,832</u>	<u>148,123</u>
INCOME FROM OIL AND NATURAL GAS OPERATIONS	17,583	5,743
<u>OTHER OPERATIONS:</u>		
REVENUES:		
Revenues	6,491	19,124
Intersegment revenues	1,995	1,002
	<u>8,486</u>	<u>20,126</u>
EXPENSES:		
Operations and maintenance	4,542	18,887
Selling, general, and administrative	981	1,027
Taxes other than income taxes	734	612
Depreciation and amortization	2,679	2,254
	<u>8,936</u>	<u>22,780</u>
LOSS FROM OTHER OPERATIONS	(450)	(2,654)
<u>INTEREST EXPENSE AND OTHER INCOME:</u>		
Interest	1,327	3,358
Other income - net	(7,118)	(9,915)
	<u>(5,791)</u>	<u>(6,557)</u>
INCOME BEFORE INCOME TAXES.....	87,989	51,310
INCOME TAXES.....	<u>28,229</u>	<u>13,785</u>
NONUTILITY NET INCOME AVAILABLE FOR COMMON STOCK.....	\$ 59,760	\$ 37,525

NONUTILITY OPERATIONS

Telecommunications Operations

Income from our telecommunications operations decreased approximately \$1,900,000 compared with the six months ended June 30, 1999, primarily due to lower net earnings from our unconsolidated investments and increased operating expenses.

Revenues: Excluding earnings from unconsolidated investments, revenues increased approximately \$11,900,000, or 29 percent. This increase principally consists of the effects of the following elements:

- Increased network-services revenues, including private-line and Local Multi-Point Distribution Services revenues, of approximately \$9,000,000, primarily as a result of an increase in customer growth.
- Increased switched-services revenues, including long-distance and Internet services and sales for resale revenues, of approximately \$1,000,000 mainly because of customer growth.
- Decreased equipment revenues of approximately \$3,800,000 mainly resulting from 1999 equipment upgrades to address Year 2000 concerns and 1999 sales to a school district.
- Increased revenues of approximately \$5,300,000 associated with infrastructure investments for a PCS joint venture for which a Touch America affiliate provided equipment and engineering and construction services.

The following table shows changes from the previous year, in millions of dollars, in switched-services revenues (excluding Internet services and sales for resale revenues) and related percentage changes in minutes sold, price per minute, and customer growth:

	For The Six Months Ended	
	June 30, 2000	June 30, 1999
Revenues	\$ -	\$ 2
Minutes sold	2 %	39 %
Price per minute	(1)%	(8)%
Customer growth	18 %	33 %

Earnings from unconsolidated investments were approximately \$2,400,000 lower compared with the same period in 1999, primarily because of two items. We had anticipated losses of approximately \$1,000,000 related to Touch America's equity interest in the Minnesota PCS, LP joint venture. We expect this venture to continue to incur losses through 2003 as it expands its network and increases its marketing efforts. For the remainder of 2000, we estimate Touch America's share of these anticipated losses to be an additional \$300,000 - \$400,000 per month. Earnings from dark-fiber transactions, primarily from the FTV Communications LLC joint venture, were approximately \$2,200,000 lower than in 1999 as a result of the substantial completion of FTV's network during the second quarter of 1999. These decreases were partially offset by net earnings from other joint ventures in which Touch America owns equity interests.

Expenses: Operations and maintenance expenses increased approximately \$6,600,000 and SG&A expenses increased approximately \$3,000,000, attributable chiefly to increased customers, increased expenses and salaries as we expand

Touch America's infrastructure, and increased marketing efforts. Taxes other than income taxes increased approximately \$900,000, representing expansion of Touch America's fiber-optic network, partially offset by revised property tax assessed values for 2000. Depreciation and amortization expense increased approximately \$1,000,000, again representing increased plant in service.

Significant Acquisition: On June 30, 2000, Touch America closed its previously announced stock purchase from Qwest. As a result of the acquisition, we expect Touch America's operating revenues; operating expenses, including depreciation and amortization expenses; and operating income to increase. For more information on this acquisition, see our Form 8-K filed with the Securities and Exchange Commission on July 17, 2000, and Note 10, "Acquisition of Properties from Qwest."

Coal Operations

Income from our coal operations decreased approximately \$4,000,000 when compared with the first six months of 1999.

Revenues: Revenues from Western Energy's Rosebud Mine approximately increased \$1,400,000, largely attributable to sales to a midwestern utility under a new contract and a 3 percent increase in average revenue per ton for coal sold to the Colstrip Units. The average revenue per ton increase was primarily the result of a one-time \$2,700,000 refund in the first quarter of 1999 to a customer for final pit reclamation funds previously collected. The customer has agreed to be responsible for a portion of all final pit reclamation expenses in the future. These increases were partially offset by an 8 percent decrease in tons of coal sold to the Colstrip Units as a result of scheduled maintenance and unplanned outages at the generating plants. Revenues from Northwestern Resources' Jewett Mine decreased approximately \$2,500,000 as a 10 percent decrease in tons sold, due to scheduled maintenance at Reliant Energy's generating plants, more than offset a 5 percent increase in average revenue per ton. Average revenue per ton increased as a result of higher reimbursable mining costs per ton and slight increases in contract prices. Sales of approximately \$500,000 of petroleum coke to Reliant Energy in 2000 also augmented Northwestern Resources' revenues.

Expenses: Operations and maintenance expenses increased approximately \$2,000,000 due to higher equipment rental, reclamation, maintenance, and diesel fuel costs. These increases were partially offset by lower contract stripping expenses.

Independent Power Operations

Year-to-date 2000 income from our independent power operations increased approximately \$29,300,000 compared with year-to-date 1999.

Revenues: Excluding earnings from unconsolidated investments, revenues decreased approximately \$3,700,000 mainly because of the effects of a December 1999 agreement with the Los Angeles Department of Water and Power (LADWP). The Independent Power Group's Colstrip 4 Lease Management Division sold the leased share of Colstrip Unit 4 generation to LADWP and, in December 1999, the governing agreement was terminated and a new agreement, expiring in December 2010, was established. We received approximately \$106,000,000 from the LADWP in December 1999, which we are recognizing in earnings over the new agreement period. The new agreement results in lower net revenues over future periods, but allowed us to extract the value of the existing agreement and reinvest the proceeds.

With Continental Energy's sale of its equity interest in the Brazos project in Texas, earnings from unconsolidated investments increased approximately \$34,400,000. A third party purchased all of the equity

interests of the partnership that owned the project, including the ownership interest of Continental Energy. As a result of this sale, we recorded a pretax gain of approximately \$34,300,000. With this sale, we mitigated risks associated with a contract dispute between the partnership and the power purchaser regarding the terms of the power-purchase agreement.

Expenses: SG&A expenses increased approximately \$900,000 mainly due to costs associated with implementing our enterprise resource information system and increased incentive-compensation accruals.

Oil and Natural Gas Operations

Income from our oil and natural gas operations for the six months ended June 30, 2000, as compared with the six months ended June 30, 1999, increased approximately \$11,800,000.

Revenues: The following table shows changes from the previous year, in millions of dollars, in the various classifications of revenues and the related percentage changes in volumes sold and prices received:

Oil	-revenue	\$ 4
	-volume	5 %
	-price/bbl	119 %
Natural Gas	-revenue	\$ 24
	-volume	(10)%
	-price/Mcf	30 %
Natural gas liquids	-revenue	\$ 12
	-volume	38 %
	-price/bbl	49 %
Miscellaneous		\$ 4

Oil revenues were higher as improved prices and increased production from our U.S. properties more than offset lower production in Canada. The improved natural gas revenues were primarily the result of higher commodity prices and increased production from our reserves. Partially offsetting these increases were lower trading revenues due to a shift from physical trades to financial trades in some of our Canadian operations, resulting in lower overall natural gas physical volumes. Operational changes at the natural gas processing plant in Fort Lupton, Colorado caused the increased natural gas liquids volumes. The higher volumes and market prices account for the increased revenues. Improved processing revenues at the Colorado plant resulted in higher miscellaneous revenues.

Expenses: Operations and maintenance expenses increased approximately \$27,200,000, mainly because higher prices caused an increase in the purchased natural gas and natural gas liquids costs. Decreased gas purchases in Canada partially offset these increases. Also, royalty expense increased due to the higher value of production from our reserves. Taxes other than income taxes increased approximately \$1,000,000 for the same reason royalty expense was higher. Depreciation, depletion, and amortization expenses were approximately \$1,900,000 higher because of increased oil and natural gas production from owned reserves.

Other Operations

Revenues and expenses of other operations decreased primarily because, in the second quarter of 2000, MPT&M transferred all contracts related to the electric utility's supply contract with a large industrial customer to the utility, retroactive to January 1, 2000. Revenues and expenses associated with

these contracts included revenues from sales in the secondary markets, expenses for purchased power, and gains associated with a derivative financial instrument entered into to mitigate our commodity price risk. For more information about the industrial-supply contract, see Footnote 3, "Commitments," of our 1999 Annual Report on Form 10-K, under "Sales Commitments," and Item 7A of our Annual Report on Form 10-K, "Quantitative and Qualitative Disclosures About Market Risk," under the "Utility" section of the "Other Than Trading Agreements" discussion.

Nonutility Interest Expense and Other Income

Mainly because of reduced short-term borrowings, interest expense decreased approximately \$2,000,000. Other Income - Net decreased approximately \$2,800,000 primarily because the funds available for investments in the first six months of 2000 were less than the funds available for investments in the first six months of 1999. In addition, we recorded a loss of approximately \$700,000 on the disposition of a subsidiary that conducted operations associated with our former Brazilian gold-mining activities.

Quarter Ended June 30, 2000 and 1999

Net Income Per Share of Common Stock (Basic)

We reported consolidated basic net income of \$0.34 per share in the second quarter, an increase of nearly 55 percent when compared with second quarter 1999 consolidated basic net income of \$0.22 per share. Utility earnings for the second quarter 2000 decreased \$0.07 per share, from earnings of \$0.05 per share to a loss of \$0.02 per share. Nonutility earnings for the second quarter 2000 more than doubled, increasing from \$0.17 per share to \$0.36 per share, due in large part to the gain resulting from the sale of our equity interest in the Brazos independent power project.

The December 17, 1999, sale of substantially all of our electric generating assets with a book value of approximately \$497,000,000 to PPL Montana reduced our utility's net income for second quarter 2000 compared with second quarter 1999. In addition, the voluntary electric rate reduction effective in early February 2000 negatively affected our results.

In the nonutility sector, Continental Energy Services sold its equity interest in the Brazos generating project in Cleburne, Texas on June 30 and recorded a pretax gain of approximately \$34,300,000. In addition, our oil and natural gas operations reported improved earnings as a result of higher commodity prices.

	Quarter Ended	
	June 30, 2000	June 30, 1999
Utility Operations	\$ (0.02)	\$ 0.05
Nonutility Operations	0.36	0.17
Consolidated	<u>\$ 0.34</u>	<u>\$ 0.22</u>

UTILITY OPERATIONS

	Quarter Ended	
	June 30, 2000	June 30, 1999
	(Thousands of Dollars)	
<u>ELECTRIC UTILITY:</u>		
REVENUES:		
Revenues.....	\$ 101,574	\$ 105,443
Intersegment revenues.....	320	2,778
	<u>101,894</u>	<u>108,221</u>
EXPENSES:		
Power supply.....	57,707	30,878
Transmission and distribution.....	10,390	10,731
Selling, general, and administrative.....	9,460	13,810
Taxes other than income taxes.....	9,100	12,535
Depreciation and amortization.....	9,238	13,494
	<u>95,895</u>	<u>81,448</u>
INCOME FROM ELECTRIC OPERATIONS.....	5,999	26,773
<u>NATURAL GAS UTILITY:</u>		
REVENUES:		
Revenues (other than gas supply cost revenues).....	15,220	15,328
Gas supply cost revenues.....	6,940	7,062
Intersegment revenues.....	32	137
	<u>22,192</u>	<u>22,527</u>
EXPENSES:		
Gas supply costs.....	6,940	7,062
Other production, gathering, and exploration.....	(218)	341
Transmission and distribution.....	4,172	3,667
Selling, general, and administrative.....	6,456	4,777
Taxes other than income taxes.....	3,115	3,453
Depreciation, depletion, and amortization.....	2,412	2,289
	<u>22,877</u>	<u>21,589</u>
INCOME (LOSS) FROM GAS OPERATIONS.....	(685)	938
<u>INTEREST EXPENSE AND OTHER INCOME:</u>		
Interest.....	10,194	14,442
Distributions on mandatorily redeemable preferred securities of subsidiary trusts.....	1,373	1,373
Other income - net.....	(4,986)	(1,034)
	<u>6,581</u>	<u>14,781</u>
INCOME (LOSS) BEFORE INCOME TAXES.....	(1,267)	12,930
INCOME TAXES.....	(212)	5,995
DIVIDENDS ON PREFERRED STOCK.....	922	922
UTILITY NET INCOME AVAILABLE FOR COMMON STOCK.....	\$ (1,977)	\$ 6,013

UTILITY OPERATIONS

Electric Utility

	Revenues			Volumes		
	Power Supply Expenses					
	(Thousands of Dollars)			(Thousands of MWh)		
	6/30/00	6/30/99		6/30/00	6/30/99	
REVENUES:						
GENERAL BUSINESS BUNDLED REVENUES:						
Residential	\$ 25,750	\$ 28,726	(10)%	418	443	(6)%
Small commercial, small industrial, and government and municipal	32,916	37,077	(11)%	568	644	(12)%
Large commercial, large industrial....	9,910	10,954	(10)%	271	296	(8)%
Irrigation and street lighting	4,002	3,673	9 %	51	30	70 %
Total	72,578	80,430	(10)%	1,308	1,413	(7)%
GENERAL BUSINESS DISTRIBUTION ONLY REVENUES:						
Residential	62	-	-	2	-	-
Small commercial, small industrial, and government and municipal	1,300	497	162 %	79	29	172 %
Large commercial, large industrial....	1,511	1,303	16 %	475	352	35 %
Total	2,873	1,800	60 %	556	381	46 %
TOTAL GENERAL BUSINESS REVENUES	75,451	82,230	(8)%	1,864	1,794	4 %
SALES TO OTHER UTILITIES	20,668	18,099	14 %	501	910	(45)%
OTHER	5,455	5,114	7 %			
INTERSEGMENT	320	2,778	(88)%	-	25	-
TOTAL	\$101,894	\$108,221	(6)%	2,365	2,729	(13)%
POWER SUPPLY EXPENSES:						
Hydroelectric	-	5,270	-	-	1,130	-
Steam	-	14,007	-	-	980	-
Purchased power and other	57,707	11,601	397 %	2,007	373	438 %
Total	\$ 57,707	\$ 30,878	87 %	2,007	2,483	(19)%
Dollars per MWh	\$ 28.75	\$ 12.44				

Income from electric utility operations decreased approximately \$20,800,000, or 78 percent compared to the same period in 1999, primarily because of the effects of the sale of our electric generating assets and the voluntary rate reduction effective February 2, 2000.

Revenues: Second quarter 2000 revenues decreased approximately \$6,300,000 compared with the second quarter of 1999 principally for the reasons mentioned above in the six-months-ended discussion. Weather was 8 percent warmer than normal and 20 percent warmer than in 1999.

Expenses: Power-supply expenses increased; transmission and distribution expenses decreased; SG&A expenses decreased; taxes other than income taxes decreased; and depreciation and amortization expenses decreased for second quarter 2000 compared with second quarter 1999. These changes were mainly the result of the reasons mentioned above in the discussion of the six months ended June 30, 2000.

Natural Gas Utility

	Revenues			Volumes		
	(Thousands of Dollars)			(Thousands of Dkt)		
	6/30/00	6/30/99		6/30/00	6/30/99	
REVENUES:						
Residential	\$ 12,174	\$ 12,375	(2)%	1,808	2,278	(21)%
Small commercial, small industrial, and government and municipal	5,798	5,703	2 %	857	1,059	(19)%
General business revenues	17,972	18,078	(1)%	2,665	3,337	(20)%
Less: Gas supply cost revenues (GSC)	6,940	7,062	(2)%	-	-	-
General business revenues without GSC	11,032	11,016	-	2,665	3,337	(20)%
Sales to other utilities	183	171	7 %	53	57	(7)%
Transportation	3,721	3,819	(3)%	4,880	5,437	(10)%
Other	284	322	(12)%	-	-	-
Total	\$ 15,220	\$ 15,328	(1)%	7,598	8,831	(14)%

Income from natural gas operations decreased approximately \$1,600,000 compared to the same period in 1999. Natural gas revenues decreased approximately \$300,000 in the second quarter mainly as a result of a weather-related decrease in volumes sold, which more than offset the increase in rates referred to in the year-to-date discussion. Expenses, particularly increased SG&A expenses, changed mainly for the reasons mentioned above in the discussion of the six months ended June 30, 2000.

Utility Interest Expense and Other Income

Interest expense decreased approximately \$4,200,000 and Other Income - Net increased approximately \$4,000,000 primarily due to the reasons mentioned above in the six-months-ended discussion.

NONUTILITY OPERATIONS

	Quarter Ended	
	June 30, 2000	June 30, 1999
	(Thousands of Dollars)	
<u>TELECOMMUNICATIONS:</u>		
REVENUES:		
Revenues.....	\$ 28,513	\$ 21,354
Earnings from unconsolidated investments.....	(867)	677
Intersegment revenues.....	419	126
	<u>28,065</u>	<u>22,157</u>
EXPENSES:		
Operations and maintenance.....	14,825	9,382
Selling, general, and administrative.....	4,684	2,888
Taxes other than income taxes.....	222	385
Depreciation and amortization.....	3,166	2,109
	<u>22,897</u>	<u>14,764</u>
INCOME FROM TELECOMMUNICATIONS OPERATIONS.....	5,168	7,393
<u>COAL:</u>		
REVENUES:		
Revenues.....	47,486	48,779
Intersegment revenues.....	2,102	9,836
	<u>49,588</u>	<u>58,615</u>
EXPENSES:		
Operations and maintenance.....	33,066	36,530
Selling, general, and administrative.....	4,996	4,740
Taxes other than income taxes.....	5,128	6,657
Depreciation, depletion, and amortization.....	1,797	1,799
	<u>44,987</u>	<u>49,726</u>
INCOME FROM COAL OPERATIONS.....	4,601	8,889
<u>INDEPENDENT POWER:</u>		
REVENUES:		
Revenues.....	15,932	18,734
Earnings from unconsolidated investments.....	38,209	4,131
Intersegment revenues.....	64	425
	<u>54,205</u>	<u>23,290</u>
EXPENSES:		
Operations and maintenance.....	15,678	16,177
Selling, general, and administrative.....	1,661	981
Taxes other than income taxes.....	511	456
Depreciation and amortization.....	799	784
	<u>18,649</u>	<u>18,398</u>
INCOME FROM INDEPENDENT POWER OPERATIONS.....	\$ 35,556	\$ 4,892

NONUTILITY OPERATIONS (continued)

	Quarter Ended	
	June 30, 2000	June 30, 1999
	(Thousands of Dollars)	
<u>OIL AND NATURAL GAS:</u>		
REVENUES:		
Revenues.....	\$ 82,275	\$ 76,745
Intersegment revenues.....	4,360	3,912
	<u>86,635</u>	<u>80,657</u>
EXPENSES:		
Operations and maintenance.....	64,417	66,116
Selling, general, and administrative.....	5,267	4,732
Taxes other than income taxes.....	1,601	1,553
Depreciation, depletion, and amortization.....	6,717	5,954
	<u>78,002</u>	<u>78,355</u>
INCOME FROM OIL AND NATURAL GAS OPERATIONS.....	8,633	2,302
<u>OTHER OPERATIONS:</u>		
REVENUES:		
Revenues.....	(1,215)	11,247
Intersegment revenues.....	471	561
	<u>(744)</u>	<u>11,808</u>
EXPENSES:		
Operations and maintenance.....	(3,628)	11,456
Selling, general, and administrative.....	1,205	(297)
Taxes other than income taxes.....	568	299
Depreciation and amortization.....	1,079	1,172
	<u>(776)</u>	<u>12,630</u>
INCOME (LOSS) FROM OTHER OPERATIONS.....	32	(822)
<u>INTEREST EXPENSE AND OTHER INCOME:</u>		
Interest.....	554	1,255
Other income - net.....	(2,947)	(4,418)
	<u>(2,393)</u>	<u>(3,163)</u>
INCOME BEFORE INCOME TAXES.....	56,383	25,817
INCOME TAXES.....	<u>18,911</u>	<u>7,503</u>
NONUTILITY NET INCOME AVAILABLE FOR COMMON STOCK.....	\$ 37,472	\$ 18,314

NONUTILITY OPERATIONS

Telecommunications Operations

For the quarter, income from our telecommunications operations decreased approximately \$2,200,000 compared with second quarter 1999, chiefly because of the reasons mentioned above in the discussion of the six months ended June 30, 2000.

Revenues: Excluding earnings from unconsolidated investments, revenues increased approximately \$7,500,000, or 35 percent, principally for the reasons mentioned above in the year-to-date discussion. The increase in operating revenues consists of several elements: network-services revenues (increasing approximately \$5,200,000); switched-services revenues (increasing approximately \$100,000); and revenues related to the PCS joint venture mentioned above in the results of the six months ended June 30, 2000 (increasing approximately \$4,500,000). A decrease of approximately \$2,800,000 in equipment revenues partially offset these increases.

Earnings from unconsolidated investments were approximately \$1,500,000 lower compared with the same period in 1999. This decrease was the result of Touch America's anticipated losses of approximately \$800,000 related to its equity investment in the Minnesota PCS, LP joint venture and lower income from dark-fiber transactions of approximately \$1,100,000, primarily resulting from the FTV Communications LLC joint venture. These decreases were somewhat offset by the receipt of net earnings from other joint ventures in which Touch America owns interests.

Expenses: Operations and maintenance expenses and SG&A expenses increased a total of approximately \$7,200,000, attributable chiefly to the combination of expenses mentioned above in the year-to-date discussion. Taxes other than income taxes decreased approximately \$200,000, despite increased property taxes representing expansion of Touch America's fiber-optic network, as a result of a revision in our state property tax assessed values for 2000. Depreciation and amortization expense increased approximately \$1,100,000 because of increased plant in service.

Coal Operations

Income from our coal operations for the quarter ended June 30, 2000, decreased approximately \$4,300,000 when compared with the second quarter of 1999.

Revenues: Both of our coal operations experienced lower overall revenues. Western Energy's revenues decreased approximately \$6,200,000 due to a 26 percent decrease in tons sold to the Colstrip Units, as a result of scheduled maintenance and unplanned outages at the generating plants, and a 7 percent decrease in average revenue per ton sold. These reduced sales to the Colstrip Units were partially offset by sales to a midwestern utility that began in the first quarter of 2000. Northwestern Resources' revenues decreased approximately \$2,800,000 as an 18 percent decrease in tons sold, due to scheduled maintenance at Reliant Energy's generating plants, more than offset an 8 percent increase in average revenue per ton. Average revenue per ton increased for the same reasons discussed in the six-months-ended section above. The petroleum coke sales discussed in the six-months-ended section somewhat mitigated the decreased coal revenues.

Expenses: Operations and maintenance expenses decreased approximately \$3,500,000 with lower volumes sold reducing royalties, reclamation, and contract stripping costs. These decreases were partially offset by increased maintenance expenses. Taxes other than income taxes also decreased, primarily as a result of the decreased revenues at the Rosebud Mine.

Independent Power Operations

Income from our independent power operations increased approximately \$30,700,000 compared with the same period of a year ago.

Revenues: Excluding earnings from unconsolidated investments, revenues decreased approximately \$3,200,000 mainly because of the effects of the December 1999 agreement with the LADWP discussed above in the year-to-date results. Earnings from unconsolidated investments increased approximately \$34,100,000 primarily due to Continental Energy's pretax gain resulting from the sale of its equity interest in the Brazos project, as discussed above in the year-to-date results.

Expenses: SG&A expenses increased approximately \$700,000 principally due to the reasons mentioned above in the discussion of the six months ended June 30, 2000.

Oil and Natural Gas Operations

Income from our oil and natural gas operations increased approximately \$6,300,000 versus second quarter of 1999.

Revenues: The following table shows changes from the previous year, in millions of dollars, in the various classifications of revenues and the related percentage changes in volumes sold and prices received:

Oil	-revenue	\$ 2
	-volume	7 %
	-price/bbl	87 %
Natural Gas	-revenue	\$ (4)
	-volume	(22)%
	-price/Mcf	21 %
Natural gas liquids	-revenue	\$ 7
	-volume	42 %
	-price/bbl	68 %
Miscellaneous		\$ 1

The above revenue changes were a result of the same factors discussed in the six-months-ended section above. However, the shift in natural gas trading activities in Canada more than offset the effects of higher natural gas prices and resulted in lower natural gas revenues.

Expenses: Operations and maintenance expenses decreased nearly \$1,700,000 as the decreased natural gas purchases in Canada more than offset the effect of higher natural gas prices. This decrease was partially offset by higher royalty expense due to the increased value of production from our reserves. Depreciation, depletion, and amortization expenses were nearly \$800,000 higher because of increased oil and natural gas production from owned reserves.

Other Operations

Revenues and expenses of other operations decreased primarily because of the reasons mentioned above in the six-months-ended discussion.

Nonutility Interest Expense and Other Income

Interest expense decreased approximately \$700,000 and Other Income - Net

decreased approximately \$1,500,000 mainly for the same reasons mentioned above in the six-months-ended discussion.

LIQUIDITY AND CAPITAL RESOURCES

Operating Activities --

Net cash used for operating activities was \$42,131,000 for the six months ended June 30, 2000, compared with net cash provided by operating activities of \$209,636,000 in the first six months of 1999. The current-year decrease of \$251,767,000 was attributable mainly to the \$257,000,000 prepayment received in January 1999 from a Touch America customer. Cash from the prepayment was used to reduce long-term debt and short-term borrowing and pay taxes on the prepayment and the gain resulting from the sale of our electric generating assets.

Investing Activities --

Net cash used for investing activities was \$248,333,000 for the six months ended June 30, 2000, compared with \$69,213,000 in the first six months of 1999. The current-year increase of \$179,120,000 was attributable mainly to an increase in capital expenditures by our telecommunications operations, partially offset by a decrease in capital expenditures by the utility operations and a current-year increase in proceeds received from property sales and investments.

For information regarding Touch America's investments, refer to Note 5, "Commitments." We expect our source of funds for these investments will be generated internally or borrowed from third parties. For information regarding Touch America's capital expenditures related to the Qwest properties, refer to Note 10, "Acquisition of Properties from Qwest."

Financing Activities --

Net cash used for financing activities was \$250,667,000 for the six months ended June 30, 2000, compared with \$150,539,000 in the first six months of 1999.

On January 3, 2000, we made a payment of approximately \$10,200,000 for our share of the costs associated with the Kerr mitigation plan (Plan). This amount represented our final liability for costs under the Plan through the December 17, 1999, sale date of the electric generating assets.

Two issues of Medium-Term Notes (MTNs) were retired prior to maturity in January of 2000. On January 13, 2000, we retired \$5,000,000 of 7.25 percent Series A Secured MTNs due January 19, 2024. On January 14, 2000, we retired \$7,000,000 of 8.68 percent Series A Unsecured MTNs due February 7, 2022.

We retired at maturity \$10,000,000 of 8.80 percent Series A Unsecured MTNs on February 22, 2000.

On April 13, 2000, we retired prior to maturity \$25,000,000 of our 7.5 percent First Mortgage Bonds (Bonds) due April 1, 2001.

On April 25, 2000, we offered to purchase any or all of the following series of our outstanding debt: 8.95 percent Bonds due February 1, 2022; 7.33 percent Secured MTNs due April 15, 2025; 8.11 percent Secured MTNs due January 25, 2023; 7.00 percent Bonds due March 1, 2005; and 8.25 percent Bonds due February 1, 2007. The total amount outstanding for these issues was \$190,000,000 as of April 25, 2000. On May 24, 2000, we retired \$182,700,000 of this amount, as follows:

- \$48,500,000 of 8.95 percent Bonds due February 1, 2022;
- \$20,000,000 of 7.33 percent Secured Series A MTNs due April 15, 2025;
- \$15,000,000 of 8.11 percent Secured Series A MTNs due January 25, 2023;
- \$44,600,000 of 7.00 percent Bonds due March 1, 2005; and
- \$54,600,000 of 8.25 percent Bonds due February 1, 2007.

In addition, we retired at maturity \$20,000,000 of 7.20 percent Series A Secured MTNs on June 1, 2000.

These debt retirements were made from the proceeds received from the sale of the electric generating assets.

As part of the Tier II rate filing discussed in Note 1, "Deregulation, Regulatory Matters, Sale of Electric Generating Assets, and Proposed Divestiture of Energy Businesses," we indicated our intention to retire approximately \$266,000,000 of debt. The expenses associated with the debt retirements were estimated at approximately \$20,000,000. With all retirements of MTNs and Bonds discussed above, the actual amount of debt retired (including the retirement in 1999 of \$15,000,000 of 7.875 percent Series B Unsecured MTNs due December 23, 2026) was slightly less than \$265,000,000 and the associated expenses were approximately \$9,300,000.

Our consolidated borrowing ability under our Revolving Credit and Term Loan Agreements was \$158,928,000, of which \$152,196,000 was unused at June 30, 2000. On April 4, 2000, our \$100,000,000 Revolving Credit Agreement for some of our nonutility operations terminated with no amounts outstanding. We have entered into a \$30,000,000 Revolving Credit Agreement that expires on June 28, 2001 and a \$200,000,000 90-Day Credit Agreement for use in our telecommunications operations that expires on September 26, 2000.

Altana Exploration Ltd., our wholly owned Canadian subsidiary, made payments of approximately \$10,400,000 in United States dollars (approximately \$15,300,000 Canadian dollars) during the first six months of 2000 pursuant to its revolving line of credit, resulting in a balance outstanding at June 30, 2000 of approximately \$6,700,000 United States dollars (approximately \$10,000,000 Canadian dollars).

We also have short-term borrowing facilities with commercial banks that provide committed and uncommitted lines of credit and the ability to sell commercial paper.

The Board of Directors periodically reviews our dividend policy to ensure that our dividend payout and dividend rate are appropriate given our business plan, strategy, and outlook. Our common stock dividend rate is dependent on our results of operations, financial position, anticipated future uses of cash, and other factors. In assessing the dividend policy, the Board of Directors also evaluates the effect of the sale of our generation assets and the continued growth of, and investment in, Touch America. As discussed more fully in Note 1, "Deregulation, Regulatory Matters, Sale of Electric Generating Assets, and Proposed Divestiture of Energy Businesses," on March 28, 2000, we announced our decision to separate our telecommunications business from our energy businesses through stock sales of our energy businesses, with Touch America remaining as the entity through which we will continue to conduct our telecommunications business. The Board of Directors will continue to assess and adjust our dividend policy in light of these and other developments.

For information regarding our authorization to repurchase common stock, refer to Note 9, "Common Stock."

SEC RATIO OF EARNINGS TO FIXED CHARGES

For the twelve months ended June 30, 2000, our ratio of earnings to fixed charges was 3.74 times. Fixed charges include interest, distributions on preferred securities of a subsidiary trust, the implicit interest of the Colstrip Unit No. 4 rentals, and one-third of all other rental payments.

NEW ACCOUNTING PRONOUNCEMENTS

For a discussion of new accounting pronouncements and how they are expected to affect us, see Note 13, "New Accounting Pronouncements."

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our energy commodity-producing, trading, and marketing activities and other investments and agreements expose us to the market risks associated with fluctuations in commodity prices, interest rates, and changes in foreign currency translation rates.

Trading Instruments

Because we do not use derivative financial instruments to hedge against exposure to fluctuations in interest rates or foreign currency exchange rates, commodity price risk represents the primary market risk to which our non-regulated energy-commodity producing, trading, and marketing operations are exposed. We discuss the derivative financial instruments that we use to manage this risk in Note 3, "Derivative Financial Instruments."

Electricity

In June 1998, prior to our August 1998 decision to exit the electric trading and marketing businesses, MPT&M entered into a derivative financial transaction, called a "swap," in conjunction with one of our electric retail sales contracts. That swap allows us to receive the difference between a fixed price and market-index price for electricity when the market price is less than the fixed price. When the market price is more than a fixed price, a physical purchase agreement allows us to receive the difference between the fixed price and market-index price for electricity. Effective January 1, 2000, MPT&M transferred these agreements to the electric utility, and they provide a hedge against a portion of the cost of purchasing electricity to serve the retail sales contract.

Crude Oil, Natural Gas, and Natural Gas Liquids

We have commodity risk-management policies and practices to govern the execution, recording, and reporting of derivative financial instruments and physical transactions associated with the trading and marketing activity of crude oil, natural gas, and natural gas liquids engaged in by MPT&M. These policies and practices require MPT&M to identify, quantify, and report commodity risks and to hold regular Risk Management Committee meetings.

Our Audit Committee established a value-at-risk (VaR) limit to manage our exposure to potential losses from trading activity. MPT&M must report to that committee the number of times it exceeds the established limit. MPT&M's VaR limit, including forecasts of affiliate-owned production, is \$2,000,000.

MPT&M's VaR calculation indicates how much MPT&M could lose from its trading transactions under certain assumptions. Because actual future changes in markets - prices, volatilities, and correlations - may be inconsistent with historical observations, MPT&M's VaR may not accurately reflect the potential for future adverse changes in fair values. At June 30, 2000, MPT&M's VaR calculation for physical and financial crude oil, natural gas, and natural gas

liquids transactions, including forecasts of affiliate-owned production, was approximately \$1,500,000.

From April 1, 2000, through the end of the second quarter, MPT&M reported daily adverse changes in fair values in excess of its \$2,000,000 VaR limit on five occasions. From July 1, 2000, through August 7, 2000, MPT&M reported no such occasions.

Other-Than-Trading Agreements

Commodity Price Exposure

We are exposed to commodity price risks through our utility and nonutility operations. Our utility has entered into purchase, sale, and transportation contracts for electric energy and natural gas. One of these contracts obligates us to sell electric energy to an industrial customer at terms that include a fixed price for a portion of the power delivered and an index-based price for another portion through December 2002. For 2003 and 2004, we sell all power to the customer at an index-based price. Since the sale of our electric generating assets, we have been supplying our customer with power purchased through an index-based contract that remains effective through July 2001. Our industrial customer has given us usage estimates that do not exceed the amount of power that we are committed to purchase.

We are subject to commodity price risk because the price of power under the index-based purchase contract could exceed the fixed price in our sales contract. Due to uncertainties relating to the supply requirements of the contract and uncertainties surrounding various arrangements that would allow us to serve the contractual demand, we cannot determine at this time the effects that this contract ultimately may have on our consolidated financial position, results of operation, or cash flows. We have entered into arrangements to mitigate the commodity price risk inherent in this contract, and we continue to examine our options and take steps to mitigate the commodity price risk resulting from this contract.

Our nonutility has entered into similar kinds of purchase, sale, and transportation contracts for coal, lignite, natural gas, crude oil, and natural gas liquids. Since December 31, 1999, there has been no material change in these other instruments or the corresponding commodity price risk associated with these instruments.

Interest Rate Exposure

Our primary interest rate exposure with respect to other-than-trading instruments relates to items that SFAS No. 107, "Disclosures about Fair Value of Financial Instruments," defines as "financial instruments," which are instruments readily convertible to cash. Since December 31, 1999, there has been no material change in these instruments or the corresponding interest rate risk associated with these instruments.

Foreign Currency Exposure

Our primary foreign currency exposure results from (1) our Canadian subsidiaries - Altana Exploration Company and Altana Exploration Ltd. - exploring for, producing, gathering, processing, transporting, and marketing crude oil and natural gas in Canada, and (2) MPT&M trading and marketing natural gas in Canada. (Effective January 1, 2000, we combined all of the assets, liabilities, and undertakings of our Canadian subsidiaries, Altana Exploration Ltd. and Canadian-Montana Gas Company Limited, with Altana Exploration Ltd. surviving.) Since December 31, 1999, there has been no material change in these activities or the corresponding foreign currency risk associated with these activities.

PART II
OTHER INFORMATION

ITEM 1. Legal Proceedings

Kerr Project

For information regarding the Kerr Project fish, wildlife and habitat mitigation plan, refer to Note 2, "Contingencies."

Paladin Associates, Inc.

On May 4, 2000, the United States District Court for the District of Montana granted motions for summary judgment submitted by us and North American Resources Company (NARCo), a subsidiary of our subsidiary, Entech, Inc., challenging Paladin's antitrust claims on the grounds that they lacked merit as a matter of law. The court dismissed Paladin's antitrust claims. The court also ordered that Paladin's pending state claims (alleging breach of contractual obligation and torts on the part of NARCo and us) be dismissed without prejudice to the right of Paladin to prosecute those claims in state court. The court has not yet entered its judgment, initiating the time period during which Paladin must appeal, if it elects to appeal. We cannot predict whether Paladin will appeal the court's order regarding the antitrust claims or whether it will pursue these claims in state court.

TCA Building Company

On April 26, 2000, TCA appealed the summary judgment entered against it in Texas district court. The counterclaims asserted by our subsidiary, Entech, Inc., and its subsidiary, Northwestern Resources Co., against TCA have been abated pending the resolution of the appeal. We cannot predict when this matter will ultimately be resolved.

ITEM 4. Submission of Matters to a Vote of Security Holders

- (a) Our Annual Meeting of Shareholders was held on May 9, 2000.
- (b) Security holders elected four persons to our Board of Directors at our Annual Meeting. The results of the vote were as follows:

Director	For	Against	Abstentions
Kay Foster	89,225,566	--	2,377,388
Carl Lehrkind, III	89,310,330	--	2,292,624
Deborah D. McWhinney	89,170,109	--	2,435,228
Jerrold P. Pederson	88,960,413	--	2,642,541

Directors whose term of office as a director continued after the meeting are as follows:

Tucker Hart Adams	R. P. Gannon
Alan F. Cain	John R. Jester
John G. Connors	Noble E. Vosburg
R. D. Corette	

ITEM 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Exhibit 12 Computation of ratio of earnings to fixed charges for the twelve months ended June 30, 2000

Exhibit 27 Financial data schedule

(b) Reports on Form 8-K Filed During the Quarter Ended June 30, 2000.

DATE	SUBJECT
April 4, 2000	Item 5. Other Events. Proposed Divestiture of Energy Businesses.
April 25, 2000	Item 7. Exhibits. Preliminary Consolidated Statements of Income for the Quarters Ended March 31, 2000 and 1999 and for the Twelve Months Ended March 31, 2000 and 1999. Preliminary Utility Operations Statements of Income for the Quarters Ended March 31, 2000 and 1999 and for the Twelve Months Ended March 31, 2000 and 1999. Preliminary Nonutility Operations Statements of Income for the Quarters Ended March 31, 2000 and 1999 and for the Twelve Months Ended March 31, 2000 and 1999.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized signatory.

THE MONTANA POWER COMPANY
(Registrant)

By /s/ J.P. Pederson
J.P. Pederson
Vice Chairman and Chief
Financial Officer

Dated: August 14, 2000

EXHIBIT INDEX

Exhibit 12
Computation of ratio of earnings
to fixed charges for
the twelve months ended June 30, 2000

Exhibit 27
Financial data schedule

Exhibit 12

THE MONTANA POWER COMPANY

Computation of Ratio of Earnings to Fixed Charges
(Dollars in Thousands)

	Twelve Months Ended June 30, 2000
Net Income	\$ 158,815
Income Taxes	<u>49,139</u>
	\$ 207,954
Fixed Charges:	
Interest	\$ 42,716
Amortization of Debt Discount, Expense, and Premium	\$ 1,064
Rentals	<u>\$ 32,196</u>
	\$ 75,976
Earnings Before Income Taxes and Fixed Charges	<u>\$ 283,930</u>
Ratio of Earnings to Fixed Charges	<u>\$ 3.74 x</u>